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Comparing the Risk Profiles of Renewable and Natural Gas Electricity Contracts:

A Summary of the California Department of Water Resources Contracts

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Executive Summary

Objectives

Electricity markets in the United States have witnessed unprecedented instability over the last few years, with substantial volatility in wholesale market prices, significant financial distress among major industry organizations, and unprecedented legal, regulatory and legislative activity. These events demonstrate the considerable risks that exist in the electricity industry. Recent industry instability also illustrates the need for thoughtful resource planning to balance the cost, reliability, and risk of the electricity supplied to end-use customers. In balancing different supply options, utilities, regulators, and other resource planners must consider the unique risk profiles of each generating source.

This paper evaluates the relative risk profiles of renewable and natural gas generating plants. The risks that exist in the electricity industry depend in part on the technologies that are used to generate electricity. Natural gas has become the fuel of choice for new power plant additions in the United States. To some, this emphasis on a single fuel source signals the potential for increased risk. Renewable generation sources, on the other hand, are frequently cited as a potent source of socially beneficial risk reduction relative to natural gas-fired generation. Renewable generation is not risk free, however, and also imposes certain costs on the electricity sector.

This paper specifically compares the allocation and mitigation of risks in long-term natural gas-fired electricity contracts with the allocation and mitigation of these same risks in long-term renewable energy contracts. This comparison highlights some of the key differences between renewable and natural gas generation that decision makers should consider when making electricity investment and contracting decisions.

Our assessment is relevant in both regulated and restructured markets. In still-regulated markets, the audience for this report clearly includes regulators and the utilities they regulate. In restructured markets, the role of regulatory oversight of resource planning is more limited. Nonetheless, even in restructured markets, it is increasingly recognized that regulators have a critical role to play in directing the resource planning of providers of last resort – electric suppliers that provide service to those customers who choose not to switch to a competitive supplier. Our review of electricity contracts may also have educational value for those unfamiliar with the typical contents of these agreements. Details of our findings are provided in the body of the paper, but this summary is written to provide a concise alternative to reading the full report.

Overview of the Contract Sample

Power purchase agreements play a central role in allocating risks among parties in the electricity industry. These long-term electricity contracts are often held in confidence, however, with only the barest minimum of details released to the public. This has historically made a comparison of contract terms and risk allocation difficult.

Our contract sample consists of the twenty-seven long-term (three years and longer) electricity contracts signed by the California Department of Water Resources (DWR) on behalf of the customers of California's three investor-owned utilities during the California electricity crisis.[1] The DWR contracts form the basis of our analysis for several reasons:[2]

- The DWR contracted with both natural gas and renewable power plants, allowing a comparison of risk profiles and allocation in the two types of contracts.
- These agreements represent an unusually large sample of publicly available contracts, providing a unique opportunity to analyze the treatment of risk in electricity contracts.
- The DWR contracts will play an important role over the next decade in determining the shape of California's electricity industry.

The unique conditions surrounding the DWR contracting process surely yielded contracts that were executed in a hurry and that are therefore more favorable to the Sellers than would be contracts signed in more normal times. Despite these unusual circumstances, however, we believe that the terms and conditions embedded in the DWR contracts do provide insight into the risk allocation and mitigation practices common in the electricity industry. This is due in large part to the DWR's use of industry-standard contract templates. Additional work would be required, however, to more specifically assess whether the DWR's contract terms and conditions are representative of the broader market for renewable and natural gas-fired electricity contracts.

We also note that this paper reviews DWR's *original* long-term electricity contracts. Subsequently, a number of these contracts have been renegotiated or terminated. Many of these changes are favorable to the state, either reducing the cost of the power or the risks allocated to the purchaser. These renegotiated terms are <u>not</u> reflected in this paper.[3]

The DWR's original long-term contracts are expected to cost the state more than $40 billion over a ten-year timeframe. The contracts were intended to cover most of the "net short" of the state's three investor-owned utilities, representing about one-third of the utilities' electricity demands. The average contract length is ten years. The contracts include a mixture of baseload and peaking power, and dispatchable and nondispatchable plants. The dispatchable contracts are most often natural gas-fired tolling agreements.

Table ES-1 summarizes some of the key elements of the DWR's original long-term contracts. As shown, 87% of the electricity procured by the DWR under these long-term contracts is specifically designated to come from natural gas plants. Another 12% is to come from unspecified units, which are most likely to be natural gas-fired power plants. Just 1.5% of the electricity is expected to come from renewable sources.

The DWR's seven original renewable contracts total 247 MW of capacity, including 175 MW of wind, 44 MW of biomass, 25 MW of geothermal, and 3 MW of landfill gas. The wind power contracts dominate energy deliveries under the DWR's renewable purchases, and are priced lower than all but three of the DWR's gas-fired electricity contracts.

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[1] Our sample does not include the DWR's shorter-term purchases because investments in new generating plants, whether renewable or natural gas, typically require long-term contracts.
[2] Although the DWR contracts have since been assigned to the investor-owned utilities, for simplicity in this paper we state that the DWR bears costs or risks associated with the contracts rather than the utilities or their customers.
[3] The DWR's original and renegotiated contracts can be found at: http://wwwcers.water.ca.gov/.

Table ES-1. Comparison of Key Contract Terms of the DWR Long-term Renewable and Non-Renewable Contracts

	Renewable	Natural Gas	Unspecified Resources	Total Contract Sample
Number of contracts (% of total)	7 (26%)	17 (63%)	3 (11%)	27 (100%)
Weighted average* contract length (Range of contract lengths)	9.8 years (3 to 12)	9.7 years (3 to 20)	9.7 years (5 to 10)	9.7 years (3 to 20)
Weighted average* contract price (dollars per MWh)	66	70 Fixed price contracts: 68 Tolling contracts: 72	62	69
Number of contracts with new units to be built	6**	13	0	19**
Ten-year energy purchases‡ (% of total)	8,448 GWh (1.5%)	506,885 GWh (86.7%)	69,174 GWh (11.8%)	584,506 GWh (100%)
Ten-year power cost‡ (% of total)	$0.57 billion (1.4%)	$35.5 billion (88%)	$4.3 billion (10.6%)	$40.3 billion (100%)

* The weighted averages are weighted by ten-year energy purchases (or the amount of electricity to be provided by each contract through 2010).
** Includes two re-powered plants.
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001). The major assumptions made to calculate the Auditor's figures are that the DWR is assumed to purchase the maximum amount of energy available under each contract (including the dispatchable contracts), and that the cost of gas is assumed to start at $10.74 per million Btu in 2001 and to fall to $4.68 per million Btu in 2010. All dollars are in nominal dollars.

Risk Categorization

In our review of these long-term electricity contracts, we focus on some of the most important risk allocation provisions, including:[4]

- **Fuel Price Risk.** The risk that the price of the fuel used to generate electricity will exhibit variability, resulting in an uncertain cost to generate electricity.
- **Fuel Supply Risk.** The risk that the fuel supply to a power plant will be unreliable, resulting in the inability to generate electricity in a predictable and dependable manner.
- **Performance Risk.** The risk that the Seller may not be willing or able to deliver electricity according to the contractually prescribed requirements in terms of time and quantity.
- **Demand Risk.** The risk that the electricity that has been contracted for will not be needed as anticipated, or that there will not be enough electricity to meet fluctuating demand.
- **Environmental Risk.** The financial risk to which parties to an electricity contract are exposed, stemming from both existing environmental regulations and the uncertainty over possible future regulations.

[4] We acknowledge a certain amount of overlap among these categories, for example, fuel supply, performance, and demand risk are all related. Environmental and regulatory risks are also related.

- **Regulatory Risk.** The risk that future laws or regulations, or regulatory review or renegotiation of a contract, will alter the benefits or burdens of an electricity contract to either party.

The parties to an electricity contract face numerous other sources of uncertainty, including the risk that the transmission system will be unreliable and the risk that a party to the contract will default on the contract, for example by entering into bankruptcy. These risks are not addressed explicitly in paper, but default risk in particular is addressed peripherally in our discussion of other risk elements.

Fuel Price Risk in Electricity Contracts

Fundamentals: Fuel price risk is among the most significant risks in the electricity industry, and electricity contracts must therefore allocate the risk that the price of fuel will exhibit variability. A party's exposure to fuel price risk in an electricity contract depends on three factors: (1) the variability of the fuel's price, (2) the *allocation* of fuel price risk between the parties to the contract, and (3) the ability of a party to *mitigate* the risk to which it is exposed.

Among the fuels most commonly used to generate electricity, natural gas is the most volatile in price. Long-term gas-fired electricity contracts generally allocate natural gas price risk through one of three pricing mechanisms: (1) fixed prices, (2) indexed prices, or (3) "tolling" agreements.

FUEL PRICE RISK: SUMMARY

Renewable and gas-fired electricity contracts pose substantially different fuel price risks. The ability of renewable energy facilities to offer price stability is a frequently mentioned benefit of these energy sources. It deserves note, however, that gas-fired generators can also offer fixed prices per MWh of electricity generated. The DWR, for example, primarily protected itself from fuel price risk by contracting at fixed prices with natural gas generators rather than opting for the more complete physical hedge that renewable energy can provide.

- **Fixed-price electricity contracts** establish a fixed and known price per MWh of delivered electricity. The Buyer presumably pays a premium for fixed-price contracts with natural gas generators because the generators have to manage the fuel price risk to which they are exposed, which increases the generators' costs.
- **Indexed-price contracts** generally index the price of electricity to either inflation or to the cost of another commodity, for example, the cost of the fuel used to generate the electricity. When indexed-price electricity contracts are indexed to the price of the natural gas used to generate the electricity, the fuel price risk is allocated to the Buyer because the Buyer receives a variable-priced product.
- **Tolling contracts** provide the Buyer a service: the right to use the Seller's power plant to convert natural gas to electricity. The Seller is paid not only for the use of its facility, but also for simply being available to generate. The Buyer pays for the natural gas used to generate the electricity. The risk of fuel price variability is therefore clearly allocated to the Buyer in

tolling contracts. The Buyer can then choose to reduce its fuel price risk exposure through fixed-price physical gas supply contracts, gas storage, or financial hedging instruments.

In contrast to the volatility of natural gas prices, renewable resources in general have a less-variable and frequently free fuel cost stream, typically resulting in less fuel price risk for either party to an electricity contract. Hence, it is more common to have fixed-price contracts for renewable electricity than for natural gas generated electricity. Since the use of renewable resources decreases fuel price risk for both parties to a contract, all else equal, a fixed-price renewable electricity contract is a more complete hedge against fuel price risk for the Buyer than a fixed-price contract for natural gas generation. This is because the Buyer of a fixed-price gas-fired electricity contract still bears some residual fuel price risk in the event that the Seller defaults on the contract because of a natural gas price increase, therefore exposing the Buyer to the short-term market for electricity purchases. Experience shows that the risk of contract default or renegotiation in such cases can be significant for gas-fired contracts, though the absolute magnitude of this risk is hard to assess and therefore deserves additional analysis. More generally, if an increase in renewable electricity generation reduces natural gas consumption on a regional or national basis, then it will put downward pressure on natural gas prices overall, resulting in an economic benefit to consumers.

The DWR Contract Sample: The majority of the electricity DWR has under contract for the next decade will come from power plants fueled by natural gas – a fuel whose price has exhibited substantial volatility. Against this backdrop, the DWR hedged its fuel price risk exposure primarily through the use of fixed-price non-renewable (primarily natural gas) electricity contracts. These contracts provide 57% of the electricity the DWR has under contract, and demonstrate that fuel price risk can be hedged to some degree through fixed price contracts with natural gas-fired generators.

Another 41% of the DWR's electricity supply will come through tolling contracts, in which the DWR directly bears fuel price risk. [5] (The DWR did not use index-based electricity contracts.) In these cases, the DWR can manage its fuel price risk by signing a long-term contract for natural gas supply, by agreeing with the Seller on a fuel supply plan that meets the DWR's risk exposure needs, or else by purchasing natural gas on the spot market and using financial instruments to hedge the price volatility. Almost all of the tolling contracts in the DWR sample allow the DWR to dispatch the power plant. In effect, under a tolling agreement with a dispatchable plant, the DWR accepts fuel price risk in exchange for a reduction in its exposure to demand risk.

The elasticity of the total cost of the DWR contracts to natural gas prices is only about 0.2. That is, a 10% increase in natural gas prices over a ten year period will lead to a 2% increase in the DWR's power costs over that same time period. While this demonstrates that the DWR has protected itself reasonably well against movements in natural gas prices, the sheer size of the DWR's contracting efforts means that its exposure to natural gas price increases could be significant in absolute figures. For example, the DWR's total cost could vary on the order of $2 billion based on reasonable scenarios of future natural gas prices.

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[5] Note that here and elsewhere we use percentage figures that are provided by the State Auditor, and which assume that the DWR purchases the maximum amount of energy available under each contract, including the dispatchable contracts. As a practical matter, the DWR is unlikely to purchase this maximum quantity.

More generally, the DWR contracts provide for the construction of a significant amount of new natural gas power plants, which will presumably increase California's reliance on natural gas and may have important implications for the vulnerability of the state's economy to natural gas price volatility. The DWR's recently renegotiated contracts convert some of the fixed-price natural gas contracts to tolling agreements, potentially further increasing the DWR's fuel price risk exposure.

Renewable electricity only provides 1.5% of the DWR's total ten-year electricity purchases. The DWR's renewable energy contracts are all at fixed prices, illustrating the ability of renewable generators to offer a natural hedge against fuel price movements. These contracts, especially those with wind, geothermal, and landfill gas generators, provide the greatest possible mitigation of fuel price risk for both the DWR and the Sellers.[6] For the DWR, the mitigation of fuel price risk provided by these renewable electricity contracts is greater than the mitigation provided by fixed-price natural gas contracts or hedged tolling agreements, because of the default risks described earlier.

In sum, these renewable electricity contracts *reduce* fuel price risk for both parties, whereas hedged natural gas contracts simply *shift* fuel price risk to other parties. Nonetheless, with such a small amount of renewable energy under contract, the DWR clearly did not use renewables as a significant hedge against fuel price risk, despite the fact that renewable energy offers a more complete hedge than fixed-price gas-fired electricity contracts.

Fuel Supply Risk in Electricity Contracts

Fundamentals: The ability of a power plant to reliably generate electricity depends, in part, on the dependability of its supply of fuel. The reliability of the supply of natural gas to a power plant depends on both the reliability of the supply of the gas itself, and the reliability of the transportation of the gas to the plant.

The supply of natural gas to a power plant can be interrupted due to "normal" supply and transportation constraints (e.g. pipeline constraints), or due to catastrophes. The parties to an electricity contract can usually manage the risk of a "normal" natural gas supply or transportation constraint by requiring firm fuel and transportation contracts. (In certain circumstances, however, even firm natural gas contracts may be interrupted). On the other hand, the risk of a catastrophic interruption of natural gas supply to a power plant (e.g. an attack on the pipelines that bring gas into California) cannot be readily reduced through the terms of an individual contract. This risk can only be managed through resource diversification.

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[6] Since the DWR's biomass contracts are fixed-price, the Sellers bear the biomass price risk. Similar to the fixed-price natural gas contracts, the DWR still bears some residual fuel price risk (i.e., contract default risks) in the biomass contracts. Biomass contracts have at least one advantage and one disadvantage compared to natural gas contracts. Since fuel supply for biomass power plants is local by nature, the volatility of biomass prices is less systematic than natural gas prices – that is, a spike in biomass prices at one plant will not necessarily affect the price of fuel for all biomass generators in the state simultaneously. On the other hand, there is no index price for biomass, which makes it difficult to hedge biomass price risk with financial instruments; the Seller's only option is to contract for fixed-price physical supply to mitigate its fuel price risk exposure.

The supplies of many renewable fuels used to generate electricity are often less predictable on an hour-to-hour and day-to-day basis than the supply of natural gas. Solar and wind resources have a significant amount of hourly, daily, and seasonal variation that is difficult to predict with precision in advance. Landfill gas and geothermal resources have much less day-to-day variation, but their supply can be unpredictable over longer time scales. Biomass facilities have to acquire and transport fuel to the plant; accordingly, biomass electricity contracts can manage fuel supply risk in a similar manner to natural gas contracts, by requiring firm fuel and transportation contracts from biomass suppliers.

In some cases, renewable fuel supply variability is systematic, for example, cloudy weather can reduce solar energy production on a statewide basis. In contrast to natural gas fuel supply risk, however, uncertainty in renewable fuel supply is frequently unsystematic, affecting individual renewable plants or resource areas, but not affecting all plants simultaneously.

FUEL SUPPLY RISK: SUMMARY

Renewable electricity contracts and natural gas-fired electricity contracts face different challenges with regards to fuel supply risk. Natural gas-fired power plants are more vulnerable to systematic and catastrophic interruptions in fuel supply (affecting many plants simultaneously), while renewable generation is sometimes far more vulnerable to "normal" day-to-day variability in fuel supply. These differences are reflected in the DWR contract sample.

The DWR Contract Sample: The DWR bears some fuel supply risk in all of their contracts, whether renewable-based or natural gas fueled. Since fuel supply interruptions are often likely to be out of the Seller's control, the DWR's natural gas contracts generally excuse the Seller from delivering power in the event of a fuel supply interruption if the Seller has firm fuel supply and transportation arrangements. If the Seller does not have such firm arrangements, a fuel supply interruption may not be excused; in these cases the Seller is sometimes required to pay the DWR's cost of replacement power ("cover damages") and/or is penalized according to the contract's availability provisions.

The DWR therefore bears the risk of a catastrophic natural gas supply interruption in all of its non-renewable contracts. The DWR also bears the risk of other, less dramatic fuel supply or fuel transportation interruptions in most of the gas-fired electricity contracts, though requirements for firm (non-interruptible) gas supply and transportation delivery in some of the contracts mitigates this risk. Since the DWR contracts increase California's overall reliance on natural gas, the contracts may also make the state's electrical grid more vulnerable to natural gas supply interruptions.

Renewable energy contracts may help diversify the DWR's fuel supply portfolio and thereby decrease the risk that a systematic natural gas supply interruption will disrupt California's electrical grid. That said, the DWR's renewable contracts vary considerably in how much fuel supply risk is allocated to the DWR. In aggregate, however, "normal" hourly, daily, seasonal, and yearly variations in fuel supply are a larger concern in these contracts than they are in the natural gas contracts. The DWR's wind power contracts, for example, offer as-available supply and therefore the Buyer must manage considerable hourly, daily, and seasonal supply variations. The DWR's other renewable energy contracts do not have as variable a fuel supply and can therefore provide a firmer supply of electricity, but even these contracts expose the DWR to a greater degree of "normal" variability in supply than do the DWR's natural gas contracts.

Performance Risk in Electricity Contracts

Fundamentals: Performance risk is defined here as the risk that the Seller may not be willing or able to deliver electricity according to the contractually prescribed requirements in terms of time and quantity. Parties to an electricity contract are able to better control and manage (as opposed to just allocate) performance risk than any other risk discussed in this paper. Clearly, the Seller is best able to control the performance of its power plant(s). Contracts therefore allocate a substantial amount of performance risk to the Sellers, and provide penalties and incentives to ensure that the Sellers perform adequately.

PERFORMANCE RISK: SUMMARY

Performance risks are largely manageable, and the DWR's contracts provide a number of incentives and penalties to the Sellers to mitigate performance risk. Major differences in how performance risk is handled exist between the DWR's dispatchable and non-dispatchable contracts, regardless of fuel source. We find that the treatment of performance risk in the renewable contracts is largely similar to, though a bit more lenient than, the treatment of those same risks in the DWR's non-dispatchable contracts for non-renewable energy.

To the extent that renewable generation is based on a variable underlying fuel stream (e.g., wind), some renewable contracts clearly cannot have the same requirements for energy delivery as a contract for natural gas-fired generation. These issues of dispatchability, controllability, and predictability are covered in the Demand Risk section of this paper. Under performance risk, we examine the more limited and mundane clauses that penalize or encourage parties to a contract to meet their contractually determined delivery requirements, whatever those requirements might be.

Our analysis of performance risk is divided into two periods: (1) during the construction of a power plant, and (2) during the operation of a power plant. The major sources of uncertainty during the construction of a power plant are whether the plant will be built on time, and whether the plant will be built within budget. The major sources of uncertainty during the delivery period of an electricity contract are how efficiently the power plant will be operated, and how reliably the Seller will supply the amount of energy or capacity that was contracted for.

The allocation of performance risk during the delivery period of a contract is managed in part by the firmness of the contract, which determines under what circumstances the Seller is excused from delivering electricity. Most contracts are for either "unit-contingent" or "firm" electricity products (some of the renewable contracts are "as-available", which can be viewed as a particularly lenient unit contingent contract). A unit-contingent contract excuses the Seller from delivering power when the Seller's specified generating facilities are unavailable either due to a forced outage, or to an event that was not anticipated as of the date the contract was executed, and that is not within the reasonable control of (or due to the negligence of) the Seller. Firm contracts only excuse the Seller's performance during an event of force majeure.

The DWR Contract Sample: Not surprisingly, almost all of the DWR contracts that require new plant construction allocate the risk of construction cost over-runs to the Seller. In most of the contracts, the parties share the risk that a power plant will not be built according to schedule; most contracts allow the DWR to terminate the contract if a unit does not reach operation by a specified deadline, and in some contracts the Seller must also pay a financial penalty.

During the delivery phase of the contracts, there are considerable differences in the treatment of performance risk between the DWR's dispatchable and non-dispatchable contracts, regardless of fuel source.[7]

- The DWR's **dispatchable** gas-fired contracts are commonly tolling agreements and contain four key methods to control performance risk. First, many of these contracts require annual testing of the capacity of the power plant to determine the capacity charge. Second, many of the dispatchable contracts require periodic testing or calculation of the plant's heat rate to determine the fuel charge. Third, most of the contracts have availability requirements to ensure that the power plant is available to generate power when needed, and the contracts financially penalize the Seller if the availability requirement is not met. Finally, some of the dispatchable contracts require the Seller to pay "cover damages" for unexcused failures to deliver scheduled power; which outages qualify as excused outages is determined by the "firmness" of the contract.

- The DWR's original **non-dispatchable** non-renewable contracts, which were expected to provide 70% of the DWR's energy over the next decade, have fewer performance concerns to manage than the dispatchable contracts. Because the Seller is only paid when electricity is delivered (unlike the dispatchable contracts, which also contain capacity payments), the non-dispatchable contracts provide the Seller a built-in incentive to perform. All of the DWR's conventional non-dispatchable contracts also require the Seller to pay cover damages for unexcused failures to deliver power. Whether a failure to deliver is excused or not is dependent, in part, on whether the contract is for unit-contingent or firm delivery.

The DWR's renewable energy contracts are all non-dispatchable, and are therefore best compared to the DWR's other non-dispatchable contracts. To the extent that renewable generation is based on a variable underlying fuel stream, some renewable contracts clearly cannot have the same requirements for energy delivery as a contract for natural gas generation. While some sources of renewable energy are therefore held to lower energy delivery standards than are natural gas plants (see the next section on Demand Risk), we find that the treatment of performance risk in the renewable contracts is largely similar to, though a bit more lenient than, the treatment of those same risks in the DWR's non-dispatatchable contracts for conventional energy.

[7] It deserves note that the California State Auditor expressed concern that many of the contracts contain performance risk terms that are excessively lenient for the Sellers; many of the renegotiated contracts strengthen the performance risk terms.

One of the differences between the performance risk clauses in the renewable and natural-gas contracts is that the renewable contracts do not financially penalize the Seller if a power plant is delayed in reaching commercial operation (other than allowing the DWR to terminate the contract), whereas several of the natural gas contracts contain penalties in addition to the DWR's termination rights. The DWR also assumed additional performance risk in the two wind contracts by agreeing to bear any ISO imbalance charges that might arise due to imprecise scheduling, which is an aspect of performance risk that is not a significant concern in the other DWR contracts. The use of cover damages and availability guarantees also differ somewhat between the DWR's renewable and non-renewable contracts.

Demand Risk in Electricity Contracts

Fundamentals: Electricity is a unique commodity because it must be simultaneously produced by the supplier and utilized by the customer in real time. Since electricity demand is variable and uncertain, the parties to electricity contracts face "demand risk:" uncertainty over whether the electricity that has been contracted for will be sufficient (but not "overly" sufficient) to meet load.

DEMAND RISK: SUMMARY

The DWR primarily managed its demand risk by purchasing about one quarter of its total electricity through dispatchable natural-gas contracts. None of the DWR's renewable contracts are dispatchable, and most of the renewable contracts do less to mitigate the DWR's demand risk than even the non-dispatchable natural-gas contracts. In particular, with one exception, the renewable contracts do not offer fixed energy-delivery schedules.

The owner of a portfolio of electricity supplies must design the portfolio to be able to supply electricity to follow the customers' load; this requires the use of some dispatchable contracts.[8] A dispatchable contract allows the party purchasing the power to tell the Seller how much electricity to generate and when to do so, within specified constraints. Utilities or other load-serving entities only need enough dispatchable power to "top-off" the electricity provided by non-dispatchable plants. A least-cost electricity supply portfolio will therefore typically contain a substantial amount of non-dispatchable electricity generation, and even energy efficiency resources. Non-dispatchable contracts generally deliver "blocks" of power (fixed amounts of electricity) during hours that are set in the contract. Non-dispatchable power is more valuable if it is delivered during peak periods and if it is for firm delivery.

Renewable generation technologies are typically more difficult to dispatch than natural gas-fired generation technologies. Some forms of renewable electricity may also deliver more power during off-peak periods than conventional energy sources, and may not be willing or able to offer fixed blocks of delivered electricity, preferring, instead, as-available delivery.

The DWR Contract Sample: The DWR reduced its exposure to demand risk primarily by purchasing about one quarter of its total electricity through dispatchable natural-gas contracts. The DWR further reduced its risk by (1) tailoring, to some degree, the delivery pattern of its non-

[8] Demand response programs might also be used to reduce exposure to this risk.

dispatchable natural-gas contracts to the utilities' expected load requirements, and (2) imposing restrictions on the timing of routine power plant maintenance. While the dispatchable contracts reduce the DWR's demand risk, they also increase the DWR's exposure to fuel price risk because almost all of the dispatchable contracts are natural gas tolling agreements. This highlights a fundamental tradeoff between demand and fuel price risks.

None of the DWR's renewable contracts are dispatchable, and most of the contracts do less to mitigate DWR's demand risk than even the non-renewable, non-dispatchable contracts. This is because, with one exception, the renewable contracts do not offer fixed energy-delivery schedules that are established well in advance of delivery (as is common in the DWR's natural gas contracts). Electricity delivery uncertainty is especially prevalent, relatively speaking, under the wind power contracts. These renewable contracts, however, represent a small fraction (less than 2%) of the non-dispatchable energy under contract. Therefore, despite the fact that some of the DWR's renewable contracts do less to reduce demand risk than the DWR's natural gas contracts, the DWR's renewable contracts in aggregate impose little risk on the state.

Environmental Risk in Electricity Contracts

Fundamentals: The laws and regulations governing the environmental impacts of electricity generation are likely to change within the term of many of the DWR's contracts , as will the cost of compliance with existing environmental regulations. These environmental compliance risks can impose potentially large costs on the parties to an electricity contract. Some possible future environmental regulations include a carbon tax (or other form of carbon regulation), a renewables portfolio standard, and further regulation of sulfur dioxide, nitrogen oxides, fine particulates, and mercury emissions.

Electricity contracts must therefore manage environmental risk: the risk related to compliance with existing environmental requirements, and the risk that future environmental regulations will affect the cost of generating electricity. When deciding what electricity contracts to sign, an electricity purchaser must account for the possible future costs of environmental compliance to which the purchaser would be exposed. Likewise, when sellers of electricity are exposed to environmental compliance risks, they will presumably increase the contract price to account for the cost of bearing the risks.

ENVIRONMENTAL RISK: SUMMARY

Renewable and gas-fired electricity contracts have different environmental compliance risk profiles. If new environmental regulations are enacted, parties to fossil fuel based contracts will likely bear additional costs not imposed on parties to renewable contracts.. *Surprisingly, a number of the DWR's gas-fired contracts do not allocate the risk of future environmental regulations in a comprehensive and explicit manner; those that do allocate much of the risk to the DWR and therefore electricity billpayers. The DWR's renewable energy contracts will reduce aggregate exposure to environmental risk, but the DWR may not fully capture these benefits because some of the contracts allow the Seller to retain the rights to the renewable energy attributes.*

Environmental compliance risks are heavily dependent on the fuel source and technologies used to generate electricity. Fossil generation technologies generally believed to cause more environmental damage than renewable generation technologies, and renewable electricity contracts can therefore mitigate environmental compliance risks. If new environmental regulations are enacted, parties to gas-fired electricity contracts will most likely have to bear additional costs not imposed on parties to renewable contracts, who may even realize financial benefits stemming from a new regulation.

How environmental compliance costs impact electricity customers depends on the allocation of this risk between the Buyer and the Seller in these contracts. Electricity contracts can allocate the cost of future environmental compliance to either the Buyer or the Seller, or the contract can split the risk between the parties. When the environmental compliance risk is due to a possible future regulation, the amount of risk to which a party is exposed is also determined by the details of how the new regulation is implemented. For example, if a future carbon tax were levied on the use of natural gas, by default the Seller would bear the cost of the carbon tax in most contracts. If the carbon tax were instead levied on the use of electricity, however, the Buyer could bear the cost. Of course, new environmental regulations might also "grandfather" existing power plants and excuse them from being subject to the new regulation altogether.

The DWR Contract Sample: The DWR contracts mostly allocate the risk of compliance with current environmental regulations to the Seller, either explicitly or by default. If the cost of meeting these regulations increases, it is the Seller that bears most of the cost. There are some notable exceptions, however, and three contracts with conventional power plants allocate the cost of acquiring pollution permits to the DWR, resulting in a potential cost exposure for the DWR on the order of a billion dollars.

Given the potential financial impact of new environmental regulations, it is perhaps surprising that a number of the DWR's non-renewable contracts do not explicitly allocate the risk of future environmental regulations in a comprehensive manner. Of those contracts that do comprehensively and explicitly allocate environmental risks, most allocate a sizable portion of those risks to the DWR and therefore the state's billpayers (a number of the contracts require the Seller to cover the costs up to a ceiling, with the DWR bearing the remaining environmental compliance costs). The DWR and the state's electricity customers could therefore face large cost increases if new regulations are implemented, with the possibility of future carbon regulation as perhaps the greatest risk. For the many gas-fired electricity contracts that do not explicitly and comprehensively address environmental compliance risks, the risks presumably fall on the Seller. However, in these cases, future environmental regulations could result in costly legal battles and/or contract defaults, shifting some of the risk implicitly to the DWR. The fact that many of the DWR's contracts fail to allocate this risk explicitly and comprehensively may be attributed to either a lack of concern about the cost of future environmental regulations or a lack of awareness of their potential cost. Our review of the DWR contracts also demonstrates that there is no "industry standard" approach to allocating these risks.

The DWR's renewable energy contracts generally reduce aggregate exposure to environmental risk because many renewable electricity sources are unlikely to be subject to future environmental regulations that greatly impact the operating costs of existing plants. The DWR will not fully benefit from the environmental risk mitigation that renewable energy contracts can provide, however, because some of those benefits were not allocated to the DWR. For example, both of the DWR's wind power contracts allow the Seller to retain the rights to the renewable attributes of the electricity, i.e. the renewable energy credits (RECs). Consequently, although the DWR is nominally purchasing 1.5% of its electricity from renewable resources under long-term contracts, only about 0.5% of the DWR's electricity comes with the RECs attached. With California's recently signed renewables portfolio standard, the DWR's decision to forfeit the rights to the renewable energy credits could expose the state to approximately $40-$80 million in additional costs.

Regulatory Risk in Electricity Contracts

Fundamentals: The electricity industry is regulated by agencies at both the state and federal levels, and over the past decade the country's electricity industry has been subject to a great deal of regulatory uncertainty. We define regulatory risk as the possibility that future laws and regulations will alter the benefits or burdens of an electricity contract.

Regulatory risk can be divided into two broad categories: (1) the possibility of changes in general regulations or laws that would affect all or most electricity contracts, for example, a nationwide carbon tax, and (2) regulatory requirements targeted at a specific contract, for example, a FERC ruling to modify a contract's price. The first category of regulatory risk was covered, in part, by our discussion of environmental risk. In this section we discuss only the second category of regulatory risk: regulatory requirements targeted at specific contracts.

Parties to an electricity contract can take two approaches in managing regulatory risk. First, contracts can try to prevent regulatory action. Second, if a regulatory authority requires a change in a contract, the contract can try to mitigate and allocate the consequences of that change.

REGULATORY RISK: SUMMARY

Both renewable and non-renewable contracts face similar regulatory uncertainties. Despite this, the DWR's gas-fired electricity contracts contain clauses designed to both prevent regulatory action, and to mitigate and allocate the consequences of a new regulatory requirement. In contrast, none of the renewable contracts attempt to prevent regulatory review of the contracts, and only two of the seven contracts designate a course of action that will be taken if a regulatory agency orders a change in the contract.

The DWR Contract Sample: Given California's particularly tumultuous recent history, the contracts in the DWR sample may not represent the standard allocation of regulatory risk in electricity contracts. Indeed, regulatory challenges to the DWR contracts began shortly after the contracts were signed: both the CPUC and the Electricity Oversight Board filed complaints with FERC, asking the agency to modify or abrogate the DWR contracts.

The DWR contracts contain clauses designed to both prevent regulatory action, and to mitigate and allocate the consequences of a new regulatory requirement. About half of the DWR's original non-renewable (primarily natural gas) contracts prevent the parties to the contracts from seeking changes in the contracts from a regulatory authority. Approximately half of the DWR contracts also state that the contract price is "just and reasonable" to try to prevent regulatory review. Meanwhile, almost all of the non-renewable contracts designate a course of action that the parties will take if a regulatory agency orders a change in the contract. Specifically, most of the non-renewable contracts specify that if a regulatory authority orders a change in the contract, either the contract price will not change or the parties will use their best efforts to reform the agreement to give effect to the original intention of the parties.

In contrast, none of the renewable contracts attempt to prevent regulatory review of the contracts, and only two of the seven renewable contracts designate a course of action that will be taken if a regulatory agency orders a change in the contract. Though both renewable and natural-gas contracts presumably face very similar regulatory risks, the treatment of these risks in the renewable contracts is not nearly as formal as in the natural gas contracts. The renewable contracts' lack of attention to regulatory risk may be attributed to either a lack of awareness about the potential risk, or else confidence in the "just and reasonable" nature of the contract terms.

Conclusions

The DWR's original long-term electricity contracts, upon which our analysis in this paper is based, will help define California's electricity system over the coming decade. The DWR contracts provide for the construction of a significant amount of new natural gas-fired power plants. This may have important implications for the vulnerability of California's economy to natural gas price volatility and possible systematic interruptions in natural gas supply.
Our review of the DWR contracts reveals an obvious conclusion: natural gas-fired and renewable generation technologies have inherently different risk profiles. The allocation of these risks in electricity contracts results in substantially different risk burdens for each party to a contract. Sweeping statements on whether renewable generation is "more risky" or "less risky" than gas-fired generation, however, are simply not possible. Whether a particular generation source is more or less risky depends on the risks being considered, the perceived or actual importance of those different risks, and the risk profile of the rest of the portfolio of resources.

- ***Advantages of Renewable Energy:*** What is clear is that renewable energy production does mitigate certain risks relative to natural gas-fired power plants. Specifically, of the risks analyzed in this paper, renewable energy contracts provide the most value relative to natural gas-fired contracts by mitigating fuel price and environmental compliance risks. Though fuel price risk can also be managed with fixed-price gas-fired electricity contracts (or financial hedging tools), shifting this risk to the Seller will presumably increase the contract price, and some residual contract default risk will remain for the Buyer. Environmental compliance risks can similarly be allocated to natural gas generators, though our contract sample finds that the allocation of these risks to the Buyer is quite common. As with fuel price risk, shifting the full environmental compliance risk to the Seller may be impossible, and will likely add to the contract price. The use of renewable energy can avoid these costs and risks.

- ***Advantages of Natural Gas:*** On the other hand, it is equally clear that gas-fired electricity contracts have certain advantages over renewable energy contracts. In particular, gas-fired generation can provide far better protection against short-term demand risk than most forms of renewable energy: renewable energy contracts are rarely dispatchable, and renewable electricity is sometimes delivered on an “as-available” basis. The level of demand risk imposed by renewable energy sources depends critically on the type of renewable generation: biomass and geothermal can sometimes offer firm blocks of power, while wind is typically sold on an as-available basis. While renewable energy generators may be able to contract with intermediaries to further “firm-up” their deliveries, this will come at a cost.

- ***The Grey Area:*** Renewable and natural gas-fired generation face different challenges with regards to fuel supply risk. Natural gas-fired power plants are more vulnerable to systematic and catastrophic interruptions in fuel supply (affecting many plants simultaneously), while renewable generation is more vulnerable to “normal” hourly, daily, seasonal, and annual variability in fuel supply. Among the different types of renewable generation, the degree of fuel supply risk varies substantially. Prioritizing the relative importance of these different risks is somewhat subjective and will depend on the overall portfolio of fuel supplies that is used to generate electricity. Our contract sample also suggests that gas-fired generation may mitigate certain performance risks relative to renewable electricity; this finding may be limited to the DWR contracts, however, because, in principal, performance risks could be handled equivalently between renewable and natural gas generators. Finally, neither natural gas nor renewables have a clear advantage with regards to regulatory risk.

Although all of the risks discussed in this paper are important, it is sometimes unclear whether regulators, utilities, and other energy purchasers analyze all of the trade-offs between all of the various risks. Utilities, for example, appear to place a particular emphasis on demand risks, which favors investment in natural gas-fired generation technologies. Historically, less emphasis seems to have been placed on fuel price and environmental compliance risks, which might otherwise favor renewable technologies. Our hope is that a better understanding of the risks and risk allocation practices associated with different forms of electricity production will help utilities, regulators, and others make more objective investment decisions in the future.

1 Introduction

1.1 Overview

Electricity markets in the United States have experienced unprecedented instability and change in the last several years. While the "energy crisis" in California is no longer front-page news, electricity prices remain volatile, credit concerns dominate the industry, and the previously unrelenting move towards competitive wholesale and retail markets has stalled in some regions.

These events demonstrate yet again the considerable risks that exist in the electricity industry, from the perspective of both industry participants and end-use electricity consumers that ultimately must pay the bill. For consumers, electricity is considered essential for everyday life, and degraded electricity reliability or increased electricity bills can impose heavy financial burdens on residential, commercial, and industrial customers alike. For the electricity industry, especially given the sizeable capital investments required to build electricity generation facilities, increased risk complicates investment decisions and can create substantial financial duress.

The risks that exist in the electricity industry depend on many factors, including investment decisions that are made about the types of generation facilities to build and the contracting strategies used to bring those facilities on line. Natural gas has become the fuel of choice for new power plant additions in the United States. To some, this emphasis on natural gas signals the potential for increased risk, especially price risk because the underlying cost of natural gas has exhibited considerable variability. Also vying for increased attention in the United States are renewable energy resources: wind, biomass, geothermal, hydropower, and solar energy. Though historically supported through direct public policy measures, the cost of renewable energy supply has declined, making it possible in some circumstances to make the case for renewable energy based on cost alone. Of particular importance to this paper, renewable resources are also frequently noted to benefit society by reducing certain risks relative to conventional fuels such as natural gas (e.g., Hoff 1997). And yet, some types of renewable generation impose new and different risks on the electricity system.

Recent industry developments demonstrate the need for thoughtful resource planning to balance the cost, reliability, and risk of electricity supply to end-use consumers. In balancing different supply options, utilities, regulators, and other resource planners must consider the unique risk profiles facing each generating source (Harrington et al. 2002).

1.2 Objectives and Methodology

This paper compares key aspects of the risk profile of natural gas and renewable energy resources. We do this through an evaluation of the allocation of risks in long-term power purchase contracts for both gas-fired and renewable generation. Our comparison highlights some of the key differences between the two types of resources that decision makers must consider when making electricity investment decisions.

Our assessment is relevant in both regulated and restructured markets. In still-regulated markets, the audience for this report clearly includes regulators and the utilities they regulate. In restructured markets, the role of regulatory oversight of resource planning is more limited. Nonetheless, even in these markets, it is increasingly recognized that regulators have a critical role to play in directing the resource planning of providers of last resort – electric suppliers that provide service to those customers who choose not to switch to a competitive supplier.

We focus on power purchase agreements because these contracts play a central role in allocating risks among parties in the electricity industry. The amount of risk that any particular party bears depends in large part on how risks are allocated in these contracts.[9] The allocation of risks in the electric industry, in turn, influences electricity investment decisions, and thereby has a significant impact on what types of power plants are built and the overall portfolio of electricity supply.[10]

This analysis of the treatment of risk in long-term gas-fired and renewable electricity contracts is drawn entirely from our review of the contracts signed by the California Department of Water Resources (DWR) during the California electricity crisis of 2000-2001. We reviewed the DWR's long-term electricity contracts and summarized the provisions that allocate risks, focusing on financial and reliability risks from the perspectives of both parties to the contracts. In addition, we reviewed the California State Auditor's report on the DWR contracts, and we use the Auditor's calculations of the amount of energy to be provided by each contract and the contract costs as the basis for many of our calculations (California State Auditor 2001). Finally, we reviewed several other analyses of the DWR contracts, including an analysis by JBS Energy (Marcus 2002) and two filings at the Federal Energy Regulatory Commission (FERC) in protest of the DWR contracts submitted by the California Public Utilities Commission (CPUC) and the California Electricity Oversight Board (EOB) (CPUC 2002; EOB 2002).

The DWR contracts form the basis of our analysis for several reasons:

- First, the DWR contracts will play an important role over the next decade in determining the shape of California's electricity industry – an industry that provides an essential input to one of the largest economies in the world.
- Second, the contracts represent an unusually large sample of publicly available contracts, providing a unique opportunity to analyze the treatment of risk in electricity contracts.[11]
- Third, the DWR contracted with both natural gas and renewable power plants, allowing a comparison of the risk profiles of the two types of contracts.
- Finally, although the DWR contracts were not executed in a fully competitive market, the contracts are based on industry-standard contract templates and therefore may provide broader insights into the risk allocation practices common in competitively bid contracts.

[9] The amount of risk that a party is exposed to also depends on the party's ability to mitigate the risks that it bears.
[10] This paper does not include an analysis of the various other contracts – such as financing and fuel supply agreements – and regulations that are associated with the long-term power contracts that we analyze, and therefore does not represent a complete analysis of the allocation of risks associated with our sample of power projects. For an analysis of the allocation of risks between financial institutions and private power plant developers in loan agreements, see Kahn et al. (1992).
[11] The FERC also has on file a large number of electricity contracts, but these contracts are often redacted, making them difficult, if not impossible to analyze.

We focus on the most important risk allocation provisions in the contracts. Risks evaluated in this paper include fuel price and supply risks, performance risk, demand risk, environmental compliance risk, and other regulatory risks. Definitions of these risks, and detailed summaries of how they are allocated in the DWR's renewable and gas-fired electricity contracts, are provided later.

Our review of the DWR contracts occurred in early 2002. Subsequently, a number of these contracts have been renegotiated or terminated. Many of these changes are favorable to the state, either reducing the cost of the power or the risks allocated to the purchaser. We note explicitly that these renegotiated terms are not reflected in this report.[12]

1.3 Organization of Paper

The remainder of this paper is organized as follows:

- **Section 2** begins by discussing our use of the term "risk", briefly describing terms and distinctions that we use throughout the paper, and outlining the specific risks that we analyze in the DWR contracts.
- **Section 3** provides a brief overview of the context in which the DWR contracts were signed, and summarizes some of the principal terms of both the renewable and non-renewable contracts.
- **Section 4** specifically examines how the DWR's long-term contracts allocate fuel price and fuel supply risk, and highlights differences in that treatment among the renewable and natural gas-fired contracts.
- **Section 5** discusses the treatment of performance risk in long-term electricity contracts.
- **Section 6** considers the treatment of demand risk in the contracts.
- **Section 7** discusses environmental risk – the uncertainty due to environmental regulations – and how the DWR natural gas-fired and renewable contracts allocate that risk.
- **Section 8** reviews certain other aspects of regulatory risk and how those risks are allocated.
- **Section 9** offers some brief conclusions based on the principal findings of earlier chapters.

Appendix A offers a glossary of certain terms used in this paper. Appendix B lists some of the details of the DWR's contracts, by date of contract execution. Appendix C reports natural gas price forecast scenarios used in Section 4, while Appendix D provides additional detail on the treatment of environmental compliance risks in the DWR contracts (beyond that offered in Section 7). Finally, Appendix E and F provide detailed tabular summaries of each of the DWR's original contracts.

[12] The DWR's original and renegotiated contracts can be found at: http://wwwcers.water.ca.gov/.

2 Risks in Electricity Contracts: Background Concepts

2.1 An Introduction to Risk

The term "risk" in everyday life is generally used to refer to the potential for future harm: the risk of getting cancer, the risk of being in a car accident, or the risk of a nuclear power plant accident, for example. In a more formal and academic sense, however, risk simply refers to a future that is uncertain, independent of whether the future outcome will be beneficial or detrimental. For example, investing in a stock is risky, although the future value of your investment may decrease *or* increase.[13] In this paper, we adopt this more formal definition of "risk," and we use it to mean that future events or outcomes are uncertain.

It is plausible to think that society would wish to reduce the risk, or uncertainty, of electricity supply and cost. After all, it is ordinarily assumed that most people, and that society as a whole, are risk averse.[14] Most people therefore place a value on being able to predict a future outcome with certainty, and they are often willing to pay to eliminate future variability or risk. Electricity is also typically considered an essential commodity; any significant interruption in its supply can create a state of emergency and have serious economic repercussions. In addition, the short-term elasticity of demand for electricity is very low,[15] so when prices increase most residents and businesses feel they have relatively little choice but to pay higher amounts, which can be a significant burden for some. Finally, Californians have spent about 2% of the gross state product on electricity in the last several years (CEC 2002b; California Technology, Trade & Commerce Agency 2002). With such a large amount of California's income going to purchase electricity, it is important that the risks present in the industry are managed efficiently and equitably.

2.2 Types of Risks in Electricity Contracts

Many sources of risks exist in the process of building and operating a power plant, providing fuel to the plant, and transmitting the electricity produced by the power plant to a customer. The broad categories of risks present in the electricity system that we analyze in this paper are presented in Figure 1, mapped to the physical production and transmission of electricity, where applicable.

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[13] In academic circles, the states of incertitude about the future are sometimes distinguished using three different concepts: risk, uncertainty, and ignorance. Risk analysis attempts to model the future by specifying probabilities for a complete set of possible outcomes. Uncertainty is distinguished as a separate concept that is used when probabilities of outcomes are inestimable, but the complete set of possible outcomes is still known. The final concept is ignorance about the future. Ignorance exists when one is unable to assign probabilities to future outcomes, or to specify the complete set of possible outcomes (Stirling 1994). Our qualitative use of the term "risk" in this paper encompasses all three of the above-defined states of incertitude.

[14] Finance textbooks define a risk-averse investor as one who would prefer to avoid fair gambles; a fair gamble is one with a zero expected return (Ross 1999).

[15] It is believed that the elasticity of demand for electricity is very low for a variety of reasons, including the structure of utility tariffs such that most consumers do not receive accurate real-time price signals, that electricity-consuming equipment is generally long-lived and is not economic to replace when electricity prices change, and because electricity is considered to be an essential commodity. Even if consumers did receive accurate price signals, the demand elasticity of electricity would likely still be relatively low.

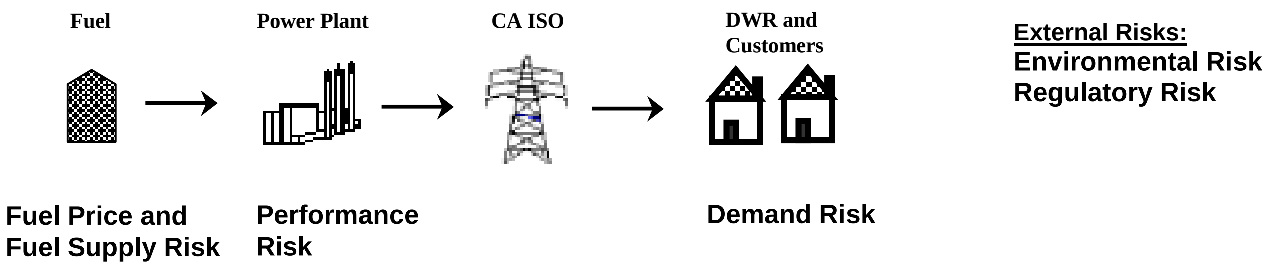

Figure 1. Categories of Risks in Electricity Contracts

Accordingly, the risks that long-term electricity contracts manage, and that are addressed in our review of the DWR's renewable and natural gas-fired contracts, are listed below. It deserves note that some of these risks overlap in significant ways, for example, fuel supply, performance, and demand risks are related; similarly, environmental compliance risks are related to regulatory risks.

- **Fuel Price Risk.** The risk that the price of the fuel used to generate electricity will exhibit variability (positive or negative), resulting in an uncertain cost to generate electricity (see Section 4).
- **Fuel Supply Risk.** The risk that the fuel supply to a power plant will be unreliable, resulting in the inability to generate electricity in a predictable and dependable manner (see Section 4).
- **Performance Risk.** The risk that the Seller may not be willing or able to deliver electricity according to the contractually prescribed requirements in terms of time and quantity (see Section 5).
- **Demand Risk.** The risk that the electricity that has been contracted for will not be needed as anticipated, or that there will not be enough electricity to meet fluctuating demand (see Section 6).
- **Environmental Risk.** The financial risk to which parties to an electricity contract are exposed, stemming from both existing environmental regulations and the uncertainty over possible future regulations (see Section 7).
- **Regulatory Risk.** The risk that future laws or regulations, or regulatory review or renegotiation of a contract, will alter the benefits or burdens of an electricity contract to either party (see Section 8).
- **Other Risks.** The parties to an electricity contract face numerous other sources of uncertainty, including the risk that the transmission system – which is necessary for the parties to complete the electricity delivery transaction – will be unreliable, and the risk that a party to the contract will default on the contract, for example by entering into bankruptcy. These issues are not addressed explicitly in this paper, but are addressed peripherally in our discussion of other risk elements.

2.3 Risk: Two Important Conceptual Distinctions

We make two conceptual distinctions here that will be used further in the pages the follow. The first relates to the distinction between risk allocation and risk mitigation, while the second deals with the difference between systematic and unsystematic risk.

- **Risk Allocation vs. Risk Mitigation:** There are two different actions that can be taken when a risk exists: the risk can be *allocated* among a group of parties, or the risk can be *mitigated* by one or more parties. The allocation of a risk determines who will bear the consequences of an uncertain future event. For example, the allocation of the risk of a future change in tax law determines who will pay for a tax increase or benefit from a tax decrease. Risk mitigation, on the other hand, reduces the uncertainty associated with a future event, or reduces the potential impact of the event. For example, in order to mitigate fuel price risk – the risk that future fuel prices will be uncertain – a developer can choose to build a wind-powered generation facility (that requires no fuel) rather than a natural gas-fired power plant. From a societal perspective, risks would ideally be allocated either to the party best able to mitigate the risk, or the party best able to bear the costs of the risk. As shown in the sections that follow, power purchase contracts address both risk allocation and risk mitigation in the electricity industry. Contracts play an important role in the electricity industry by legally binding two parties to an agreement and allocating risks between the parties. Importantly, contracts also provide mechanisms, incentives, and penalties designed to mitigate risks.

- **Systematic Risk vs. Unsystematic Risk:** Risks can either be unsystematic or systematic in nature. As defined here, an unsystematic risk affects an individual member of a group and is uncorrelated with the risk that the same event or outcome will affect other individuals. For example, the risk that one power plant will be poorly maintained and have a poor performance record may not affect the likelihood that another power plant will be maintained in a similarly poor manner. A systematic risk, on the other hand, is a risk that affects all members of a group simultaneously; the risk that an individual member of the group faces is correlated with the risk faced by the other members of the group. For example, the risk that a major natural gas pipeline entering California might be crippled and interrupt fuel supply would affect many of the state's natural gas-fired power plants simultaneously. Though our terminology here differs from that found in finance textbooks, as a general rule, systematic risks are far more socially problematic than are unsystematic risks. [16]

[16] Our definition of unsystematic and systematic risk here differs from that in finance textbooks, where these terms refer to (1) the ability to diversify risk away, and (2) the correlation of certain events with stock market returns, respectively.

3 Background on the California Electricity Crisis and the DWR Contract Sample

3.1 The California Electricity Crisis and the DWR Contracting Context

In the middle of January 2001, the credit ratings of California's utilities were downgraded to junk status due to financial difficulties caused by extremely high wholesale market prices coupled with frozen, regulated, retail rates. Generators were unwilling to continue selling electricity to the utilities, and during the ensuing two days of rolling blackouts, the State dove into the power purchasing business in order to keep the lights on in California.

To fill the void for a creditworthy power purchaser, the State enlisted its only agency with experience buying and selling power: the DWR.[17] The DWR began spending an average of $50 million per day, using appropriations from the State's General Fund, to supply about one-third of the electricity used by the customers of California's three investor-owned utilities – the so-called "net short" – from the spot market (California State Auditor 2001).[18] As shown in Figure 2, the prices in the spot market had reached levels an order of magnitude higher than the "normal" prices the state had seen over the past several years.

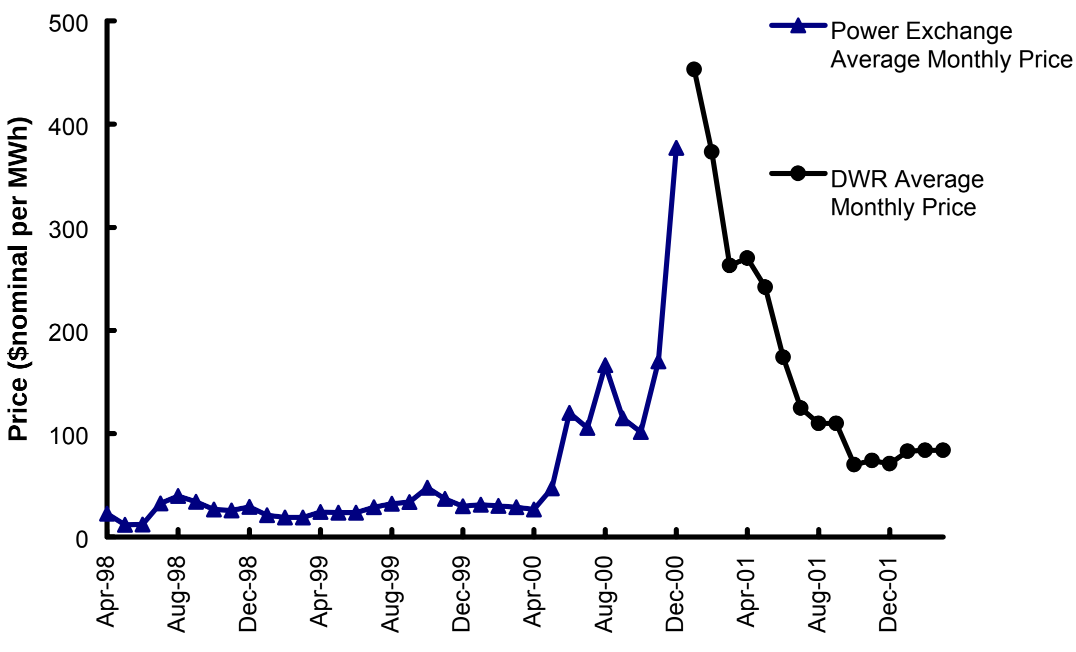

Figure 2. Wholesale Price of Electricity in California

Source: UC Energy Institute (2001); DWR (2002a)

[17] The DWR had experience contracting for 2,400 MW of power for the State Water Project; its power purchasing responsibilities immediately increased by more than five-fold when it began purchasing power on behalf of the customers of California's utilities (California State Auditor 2001).
[18] The "net short" is the difference between the electricity demanded by utility customers and the electricity supplied by utility-owned generation and qualifying facilities under contract with the utilities.

Because the DWR's short-term power purchases were quickly eating through the State's budget surplus, the California State Legislature, through Assembly Bill 1X (AB 1X), authorized the DWR to enter into long-term contracts in order to decrease the State's exposure to the volatile and expensive spot market. The DWR immediately began to implement a large and unprecedented power contracting effort.

3.2 Are the DWR Contracts Representative?

There were many "competitive" and "uncompetitive" forces influencing the DWR's contracting process; these are summarized in Table 1, below. The "competitive" factors suggest that the DWR's contracts may have terms and conditions that are representative of the electricity market as a whole. Accordingly, our comparison of DWR's renewable and natural gas-fired electricity contracts may have broad applicability beyond our contract sample. On the other hand, certain "uncompetitive" factors suggest that the DWR's contracts may not be representative of the electricity market as a whole; if true, extrapolating our findings to the broader market for long-term contracts would be inappropriate.

Table 1. Competitive and Uncompetitive Forces Influencing the DWR Contracting Process

Competitive Forces	Uncompetitive Forces
▪ Used industry-standard contracts from Edison Electric Institute (EEI) and Western Systems Power Pool (WSPP). ▪ Both DWR and Sellers had incentives to sign contracts. ▪ Both sides used experienced contract negotiators.	▪ DWR had political and financial pressure to sign contracts quickly. ▪ Tight supply/demand conditions, and possible market manipulation, gave Sellers an advantage. ▪ DWR staffing constraints and potential conflicts of interest.

The factors that suggest that the DWR's contracts are at least somewhat representative include:

- **Use of a Standard Contract Template:** The DWR contracts are based on two contract templates that are widely accepted in the electricity industry and were already in use in the Western U.S. The Edison Electric Institute (EEI) and the National Energy Marketers Association developed the main contract used by the DWR.[19] The contract was developed over a two-year period with the collaboration of utilities, generators, marketers, and others. The DWR chose to use this contract because it was familiar and acceptable to sellers of electricity, and would thereby allow for the expedited negotiation and execution of contracts. The second contract template was developed by the Western Systems Power Pool.[20] This

[19] The Edison Electric Institute is a U.S. trade association of investor-owned electric utilities (Edison Electric Institute 2002). The National Energy Marketers Association is a trade association representing producers, generators, transporters, and marketers of energy services (National Energy Marketers Association 2002).
[20] The Western Systems Power Pool is an association of utilities and electricity sellers in the Western U.S. that seeks to standardize terms used in electricity contracts, thereby promoting liquidity in the market (Western Systems Power Pool 2002).

contract had been in use for some time, and the DWR had previous experience contracting with it (California State Auditor 2001).

- **The DWR and the Sellers Both Had Incentives to Sign Long-term Contracts:** Both the DWR and the "Sellers" (the counterparties to the DWR electricity contracts) had incentives to sign long-term contracts. The DWR had intense political and financial pressure to sign contracts quickly, to slow the State's expenditures on electricity, to stabilize the market, and to prevent further blackouts. At the same time, because the DWR had become the single monopsony buyer of electricity in the market and was contracting for the majority of the power the state would need for the coming decade, the Sellers had an incentive to contract with the DWR; if a Seller did not contract with the DWR, it could be left with no one to sell its electricity to in the coming years.
- **Experienced Contract Negotiators on Both Sides:** The DWR and the Sellers both had experienced contract negotiators working for them. The DWR used negotiators previously from the Los Angeles Department of Water and Power and Southern California Edison, as well as the DWR's own experienced staff (Governor Davis 2001). The DWR also hired consultants familiar with the electricity industry and long-term contracts.

On the other hand, factors that suggest that the terms and conditions of the DWR contracts should not be extrapolated to other circumstances include:

- **Supply/Demand Imbalance, Market Manipulation, and Creditworthiness Concerns:** The Sellers' eagerness to contract with the DWR may have been tempered by the tight supply/demand conditions in the market, which gave the Sellers more power in negotiations relative to the DWR (since the Sellers knew the DWR would need to contract with *most* of them to meet the state's needs). The Sellers were also hesitant to contract with the DWR because of the DWR's own credit problems, and a broader concern that the State might not stand by the contracts (California State Auditor 2001). This combination of circumstances, combined with the possible ability of Sellers to manipulate the market, may have led to an unrepresentative set of contracts.
- **DWR Staffing Constraints and Possible Conflicts of Interest:** Though both the DWR and the Sellers used experienced contract negotiators, the DWR was clearly understaffed for the task at hand, especially in comparison to the resources the Sellers had available to negotiate contracts. In addition, it has been alleged that some of the negotiators and consultants working for the DWR had conflicts of interest that may have led to contracts that were more favorable to the Sellers (Vogel 2002).
- **Speed of the Contracting Effort:** The DWR's contracting effort was hurried; within six months, twenty-seven long-term (three years and longer) contracts had been executed to supply most of the investor-owned utilities' net short over the next ten years. Approximately 40% of the total energy now under contract to the DWR was contracted for during the first month alone. The average time to sign a contract was 7.5 days during the first month, whereas the State Auditor reported that under normal circumstances the average time to execute such a contract would be two to six months (California State Auditor 2001).

Overall, the unique conditions surrounding the DWR contracting process surely yielded contracts that were executed in a hurry and that are therefore more favorable to the Sellers than would be contracts signed in more normal times (California State Auditor 2001; Marcus 2002). The average price of the DWR contracts is also now very clearly higher than the "norm" (though, at the time the contracts were signed, this might not have been the case). Despite these unusual circumstances, however, we believe that the terms and conditions embedded in the DWR contracts do provide insight into the risk allocation and mitigation practices common in the electricity industry. This is due in large part to the use and amendment of industry-standard contract templates. Additional work would be required, however, to more specifically assess whether the DWR's contract terms and conditions are representative of the broader market for renewable and natural gas-fired electricity contracts.

3.3 Overview of the DWR Contract Sample

By October of 2001, the DWR had largely compiled its portfolio of long-term power contracts.[21] By this time, the DWR had signed twenty-seven long-term contracts for electricity, and seven short-term contracts. We define long-term contracts as those three years in length or longer. The short-term contracts, which account for less than 3% of the total energy DWR contracted for, are not included in this analysis for two reasons. First, the terms and conditions of the short-term contracts are more likely to be unique to the DWR's situation and therefore less informative about the risk allocation and mitigation practices common in the industry as a whole. Second, short-term contracts do not provide a useful comparison between the treatment of risks in renewable and gas-fired electricity contracts – one of the central purposes of this paper – because renewable electricity facilities generally need long-term contracts in order to be constructed.

The frequently stated number of fifty-nine DWR contracts differs from the thirty-four short- and long-term contracts identified above because the DWR separates many contracts into multiple transactions based on numerous factors including the product (peak, baseload, etc.) and the time period that power is provided at a given price (California State Auditor 2001). While this division of contracts is useful for practical scheduling purposes, it does not help illuminate the differences among the contracts in their treatment of risks.

Some contracts contain multiple energy transactions; in these cases, the contract contains terms and conditions that pertain to all of the transactions, and the individual transactions specify details such as the amount of power to be delivered, the pricing structure, fuel supply arrangements, etc. For the purposes of this analysis, we describe each transaction that has unique terms and conditions that affect the allocation of risks as an individual contract. (There are four Calpine transactions that are treated as individual contracts, for example, and the Dynegy contract has two transactions embedded in it that are also treated as individual contracts.) Conversely, multiple transactions (with the same counterparty) with identical terms and conditions are grouped into a single contract. (The seven Calpeak transactions, two Wellhead, and two Whitewater transactions are grouped into three contracts.)

Table 2 summarizes some of the principal terms of the twenty-seven long-term contracts highlighted in this report. All the information contained in the table was taken from our review

[21] Some short- and long-term contracts have been signed since then, but these pale in size to the original contract bundle.

Table 2. Principal Terms of the California Department of Water Resources (DWR) Long-term Contracts

Seller	Date Contract Signed	Term (years)	Pricing Structure	Product	Dispatchable?	New Units?	Resource[§]	Delivery Point[†]	MW Range	Ten-year Energy Purchases (GWh)[‡]	Price Range ($ / MWh)[‡]	Ten-Year Power Cost ($ millions)[‡]
Allegheny	3/23/2001	11	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	150 - 1,000	63,898	61	3,909
Alliance Colton	4/23/2001	10	Tolling	Peak	Partially	Yes	Natural gas (SC)	SP 15	80	1,468	379 - 141	253
Calpeak	8/14/2001	10	Tolling	Summer Super Peak	Yes	Yes	Natural gas (SC)	NP 15, SP 15	342	5,027	114 - 66	398
Calpine – 1	2/6/2001	10	Fixed	Base	No	No	Unspecified	NP 15	200 - 1,000	64,596	59	3,785
Calpine – 2	2/26/2001	10	Fixed	Peak	No	Yes	Natural gas (CC)	TBD by Seller	200 - 1,000	70,115	115 - 61	4,322
Calpine – 3	2/26/2001	20	Fixed	Base	Yes	Yes	Natural gas (SC)	NP 15	90 - 495	8,001	174 - 154	1,337
Calpine – 4	6/11/2001	3	Tolling	Peak	Yes	Yes	Natural gas (SC → CC)	NP 15	180 - 225	3,024	134 - 84	322
Coral Power	5/24/2001	11	Tolling > 2005	Base, Peak	Partially	Yes	Natural gas (SC)	NP 15, and TBD by Seller	275 - 850	28,677	249 - 57	2,292
Dynegy – 1	3/2/2001	4	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	200 - 600	14,246	120	1,702
Dynegy – 2	3/2/2001	4	Tolling	Base, Peak	Partially	No	Natural gas (CC)	SP 15	200 - 1,500	21,174	145 - 79	2,008
El Paso	2/13/2001	5	Fixed	Peak	No	No	Unspecified	NP 15, SP 15	100	2,441	115 - 127	295
Fresno Cogeneration	8/3/2001	10	Tolling	Peak	Yes	Yes	Natural gas (SC)	NP 15	21	950	179 - 92	100
GWF Energy	5/11/2001	10	Tolling	Peak	Yes	Yes	Natural gas (SC and CC)	NP 15	340 - 430	23,713	295 - 44	1,689
High Desert	3/9/2001	8	Fixed	Base	No	Yes	Natural gas (CC)	SP 15	840	51,896	58	3,010
Morgan Stanley	2/14/2001	5	Fixed	Base	No	No	Unspecified	SP 15	50	2,136	96	204
PacifiCorp	7/6/2001	10	Tolling > 2002	Base	Yes > 2002	Yes	Natural gas (CC)	NP 15	150 - 300	21,900	70**	1,533
Sempra	5/4/2001	10	Tolling > 2002	Base, Peak	No	Yes	Natural gas (SC and CC)	SP 15	400 - 1,900	93,325	160 - 57	6,238
Sunrise	6/25/2001	10	Tolling	Summer Super Peak, Base	Yes	Yes	Natural gas (SC → CC)	SP 15	325 - 560	38,888	228 - 59	2,218

Seller	Date Contract Signed	Term (years)	Pricing Structure	Product	Dispatchable?	New Units?	Resource§	Delivery Point†	MW Range	Ten-year Energy Purchases (GWh) ‡	Price Range ($ / MWh) ‡	Ten-Year Power Cost ($ millions) ‡
Wellhead	8/14/2001	10, option to extend to 20	Tolling	Peak	Yes	Yes	Natural gas (SC)	NP 15	92	4,047	142 - 78	354
Williams	2/16/2001	10	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	175 - 1,400	56,535	63 - 87	3,779
								Total Non-Renewable		**576,059**		**39,750**
Capitol Power	8/23/2001	5	Fixed	Base	No	Re-power	Biomass	NP 15	15	590	119 – 109♦	67
Clearwood	6/22/2001	10	Fixed	Base	No	Yes	Geothermal	NP 15	25	1,692	67	114
County of Santa Cruz	9/13/2001	5	Fixed	Base	No	Yes	Landfill Gas	NP 15	3	112	65	7
Imperial Valley	3/13/2001	3	Fixed	Base	No	No	Biomass	SP 15	16	362	100 – 90	34
PG&E Energy Trading	5/31/2001	10	Fixed	Intermittent	No	Yes	Wind	SP 15	67	2,017	59	118
Soledad	4/28/2001	5	Fixed	Base	No	Re-power	Biomass	NP 15	13	410	80 – 84	34
Whitewater	7/12/2001	12	Fixed	Intermittent	No	Yes	Wind	SP 15	108	3,263	60	196
								Total Renewable		**8,448**		**570**
								TOTAL		**584,506**		**40,323**

Note: only DWR contracts signed before October 2001 and with terms of three years and longer are included in this table. A number of these contracts have subsequently been renegotiated or even terminated; the "final" contract terms are not reflected in this table. Totals may not equal sum of components due to independent rounding.
§ CC = combined cycle; SC = simple cycle; SC → CC = simple cycle facility to be converted to combined cycle at some point during the term of the contract.
† NP 15 is the ISO congestion zone north of Path 15; SP 15 is the ISO congestion zone south of Path 15. Path 15 is the main transmission connection between the northern and southern parts of California; it is rated to carry 3,750 MW of power, but it is often congested (Western Area Power Administration 2002).
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001). All dollars are in nominal dollars. Ten-year energy purchases is the amount of electricity to be provided by each contract through 2010, and assumes the DWR purchases the maximum amount of energy available under each contract. Ten-year power cost is the total cost of the ten-year energy purchases.
** This contract is fixed price only until 2003. After 2003 the contract is tolling, but the State Auditor's report did not include a price estimate for this period.
♦ This is the price included in the State Auditor's report, although the contract states a fixed price of $89 per MWh.

Key

Pricing Structure	Fixed	The contract price per MWh of electricity is set in the contract. In some contracts the price is fixed throughout the term of the contract, and in other contracts the price varies according to a fixed schedule.
	Tolling	The DWR pays for the cost of natural gas, pays the generator a fee to reserve the use of the facility, and pays operating charges when the facility generates power.
Product	Base	Baseload products (7x24) can supply power all day every day. (Approximately 8,760 hours per year.)
	Peak	Peak products (6x16) generally can supply power from 6 am to 10 pm, Monday through Saturday. (Approximately 5,000 hours per year.)
	Summer Super Peak	Summer super peak products (5x8) generally can supply power for 8 hours per day, 5 days a week, from June through October. (Approximately 870 hours per year.)
	Intermittent	Wind power plants generate electricity only when wind is available.
Dispatchable?	No	Non-dispatchable contracts (also known as "must-take" or "take-or-pay") require the DWR to pay for, and the Seller to provide, all the electricity scheduled in the contract.
	Yes	Dispatchable contracts allow the DWR to choose the amount of electricity to be generated, within limits set in the contract.
	Partially	Partially dispatchable contracts require the DWR to take a minimum amount of electricity and allow the DWR to dispatch the facility in limited ways.

of the contracts, except the estimates of the ten-year energy purchases, price range, and ten-year costs, which are derived from the State Auditor's report (California State Auditor 2001).[22]

It deserves reiterating that our review of the DWR contracts occurred in early 2002. Subsequently, a number of these contracts have been renegotiated or terminated. Many of these changes are favorable to the state, either reducing the cost of the power or the risks allocated to the purchaser. These renegotiated terms are not reflected in the above table or in this report as a whole. Instead, this paper analyzes the DWR's original portfolio of contracts, though we do note some of the general changes that have been made in the renegotiated contracts throughout the paper, where applicable. Also note that the DWR contracts have since been assigned to the investor-owned utilities; for simplicity in this paper we frequently state that the DWR bears costs or risks associated with the contracts rather than the utilities or their customers.

Some of the pertinent details of the contracts, many of which are described in more depth later, include:

- **Overall Contract Cost and Amount:** The original suite of DWR contracts was expected to cost about $42.6 billion over ten years (California State Auditor 2001).[23] The contracts purchase electricity to supply most of the net short of California's three investor-owned utilities, which represents about one-third of the utility customers' power demand. The average price over ten years for the electricity is estimated to be $70 per MWh (California State Auditor 2001). This price is clearly high relative to a properly functioning electricity market, but is about one fourth the price that the DWR was paying at the time the contracts were signed.

- **Shift in Contracting Practices:** The State Auditor's report identifies a shift in the types of contracts DWR procured during the first month of its efforts and later periods (see Appendix B for a table of the long-term contracts in the order in which they were signed). About 40% of the total energy under contract was acquired during the first month. Seven out of the eight long-term contracts signed in the first month are fixed-price, and none of the contracts generate energy from renewable resources. These contracts supply a mixture of baseload and peak power from existing generation facilities. The types of contracts DWR signed in the first month reflect the DWR's desire to reduce its costs and lock in prices by signing long-term, fixed-price contracts immediately, when only existing facilities were available. After the first month of contracting, almost all of the additional contracts signed are dispatchable tolling agreements (except for the renewable contracts) with newly (or soon-to-be) constructed generating plants.

- **Contract Terms:** A number of the DWR's long-term contracts have terms of ten years or more. The weighted average (by the amount of electricity to be provided by each contract

[22] The major assumptions made to calculate the Auditor's figures are that the DWR is assumed to purchase the maximum amount of energy available under each contract (including the dispatchable contracts), and that the cost of gas is assumed to start at $10.74 per million Btu in 2001 and to fall to $4.68 per million Btu in 2010 (California State Auditor 2001). We note that both assumptions are somewhat questionable.

[23] The $42.6 billion includes both the short-term and long-term DWR contracts. As noted in Table 2, the long-term contracts analyzed in this paper account for $40.3 billion.

through 2010, or the "ten-year energy purchases") contract length of all the long-term contracts in our sample is 9.7 years. Nearly all of the contracts with terms shorter than ten years are for energy to be provided from existing units, as existing units do not require financing and therefore do not require the same contract duration as new units.[24]

- **Additional Features:** About two-thirds of the energy contracted for will come from only the six largest contracts.[25] Over 60% of the electricity to be supplied over the ten-year period will come from newly constructed generating plants. The State Auditor's analysis of the DWR contracts found that the DWR's overall portfolio includes excess baseload energy and insufficient energy during peak periods, likely requiring the DWR to sell energy for a loss at certain times, and to buy energy on the spot market when demand is high (California State Auditor 2001). Forty one percent of the electricity is supplied in "tolling" agreements, most of which give the DWR some flexibility to dispatch the facility.[26] Fifty nine percent of the electricity is supplied at fixed prices; these contracts are mostly non-dispatchable.

3.4 Comparison of the Renewable and Non-Renewable Contracts

Eighty seven percent of the electricity procured by the DWR under the long-term contracts summarized above is generated using natural gas, and 1.5% of the electricity is generated from renewable resources.[27] The contracts that do not specify what resources will be used to generate the electricity under contract will most likely use predominantly non-renewable resources; to simplify the discussion, in the rest of this paper we group the gas-fired and "unspecified" contracts as "non-renewable" contracts, unless otherwise noted. Thus, the non-renewable contracts are mostly fueled by natural gas, and make up 98.5% of the DWR's electricity.

The long-term renewable contracts are slightly cheaper, on average, than the fixed-price gas-fired electricity contracts. Using the State Auditor's estimates of future gas prices, the renewable contracts are also less expensive on a direct $/MWh basis than the DWR's tolling contracts. The renewable and gas-fired contracts have approximately the same average contract length (almost ten years). Table 3, below, provides a comparison of some of the key terms of the long-term renewable, gas-fired, and "unspecified" resource contracts,[28] while Table 4 provides additional detail on the renewable energy contracts in particular.

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[24] Many of the DWR's renegotiated contracts are shorter than the original contract lengths.

[25] The six largest providers of energy to the DWR are the Sempra, Calpine – 2, Calpine – 1, Allegheny, Williams, and High Desert contracts.

[26] Operational control of the DWR contracts shifted to the state's three investor-owned utilities on January 1, 2003. Accordingly, after 2003 it is the utilities' responsibility to dispatch the DWR contracts and arrange for gas supply.

[27] Technically, only 0.5% of the energy supplied by the DWR contracts can be considered renewable because the DWR did not acquire the "renewable credits" associated with the electricity from the two wind contracts. For a further discussion of this issue, see Section 7 on Environmental Risk.

[28] The Calpine – 1, El Paso, and Morgan Stanley contracts do not specify the resources that will be used to generate the electricity provided to the DWR.

Table 3. Comparison of Key Contract Terms of the DWR Long-term Renewable and Non-Renewable Contracts

	Renewable	Natural Gas	Unspecified Resources	Total Contract Sample
Number of contracts (% of total)	7 (26%)	17 (63%)	3 (11%)	27 (100%)
Weighted average* contract length (Range of contract lengths)	9.8 years (3 to 12)	9.7 years (3 to 20)	9.7 years (5 to 10)	9.7 years (3 to 20)
Weighted average* contract price (dollars per MWh)	66	70 Fixed price contracts: 68 Tolling contracts: 72	62	69
Number of contracts with new units to be built	6**	13	0	19**
Ten-year energy purchases‡ (% of total)	8,448 GWh (1.5%)	506,885 GWh (86.7%)	69,174 GWh (11.8%)	584,506 GWh (100%)
Ten-year power cost‡ (% of total)	$0.57 billion (1.4%)	$35.5 billion (88%)	$4.3 billion (10.6%)	$40.3 billion (100%)

* The weighted averages are weighted by ten-year energy purchases (or the amount of electricity to be provided by each contract through 2010).
** Includes two re-powered plants.
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001). All dollars are in nominal dollars.

Table 4. Comparison of Key Contract Terms of the DWR Long-term Renewable Electricity Contracts

	Wind	Biomass	Geothermal	Landfill Gas	All Renewables
Total capacity (MW)	175	44	25	3	247
Number of contracts	2	3	1	1	7
Weighted average* contract length (Range of contract lengths)	11.2 years (10 to 12)	4.5 years (3 to 5)	10 years	5 years	9.8 years (3 to 12)
Weighted average* contract price‡ (dollars per MWh)	59	89	67	65	66
Ten-year energy purchases‡ (% of renewables total)	5,280 GWh (63%)	1,363 GWh (16%)	1,692 GWh (20%)	112 GWh (1%)	8,448 GWh (100%)

* The weighted averages are weighted by ten-year energy purchases (or the amount of electricity to be provided by each contract through 2010).
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001), except the price given in the Capitol Power biomass contract was used instead of the Auditor's figure to calculate the weighted average contract price for the biomass contracts. All dollars are in nominal dollars.

The DWR's original seven long-term contracts for renewable energy provide a total of 247 MW of renewable electricity generating capacity.[29] This includes 175 MW of wind, 44 MW of biomass, 25 MW of geothermal, and 3 MW from landfill gas. Of these, the wind power contracts have the lowest price, and will provide the majority of the DWR's renewable

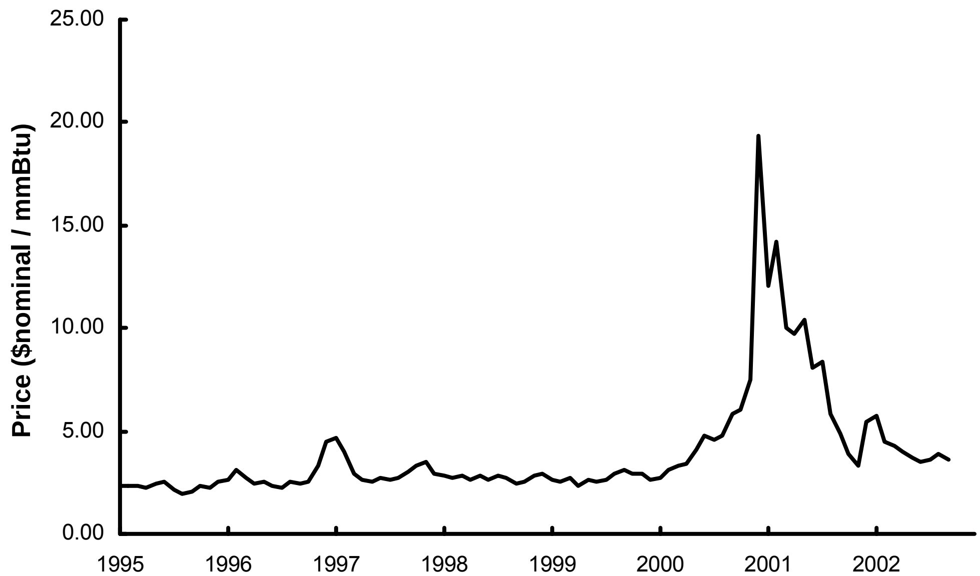
[29] It deserves note that the DWR also executed several shorter-term contracts with existing biomass facilities. These short-term contracts are not reflected in this paper.

electricity. Only three of the long-term natural gas contracts are expected by the State Auditor to have lower prices than the wind contracts.[30] The biomass contracts have the shortest contract lengths (three to five years) and the highest prices of the renewable contracts; the wind power contracts have the longest contract lengths of the renewable contracts (ten to twelve years).

[30] Only the Calpine – 1 and High Desert contracts provide power at a fixed price less than $59 per MWh. The Sunrise contract is expected to provide power at an average price of $57 per MWh (using the State Auditor's estimate of future natural gas prices), however the electricity price will depend on the price of natural gas since this contract is a tolling agreement.

4 Fuel Price and Supply Risks in Electricity Contracts

The majority of the electricity DWR has contracted for over the next decade will come from power plants fueled by natural gas – a fuel whose price has exhibited substantial volatility (see Figure 3, below). Natural gas price increases in California contributed to the extremely high wholesale electricity prices that caused California's electricity crisis. In contrast to the volatility of natural gas prices, the price of electricity generated from renewable resources is often quite stable, because, in many cases, the fuel is free (e.g. wind and solar resources) or the price of fuel (in the case of biomass) may be more stable than the price of natural gas.[31]



Source: EIA (2002)

Figure 3. Price of Natural Gas Delivered to Electric Utility Consumers in California

The resource that is used to generate electricity also has important implications for a power plant's ability to operate reliably; a generating facility's reliability depends critically on the reliability of its underlying fuel supply. Natural gas-fired power plants and renewable power plants face different challenges in obtaining a reliable supply of fuel to ensure that electricity is produced without interruption.

In this section, we first examine how the long-term DWR contracts allocate and mitigate the risk that the price of fuel will exhibit variability. We then analyze the risk that fuel supply to the generating plants will be unreliable. In both cases, we specifically compare the treatment of fuel price and supply risks in the renewable and non-renewable DWR contracts.

[31] We use the term "fuel" to describe the energy that is used to power renewable generation technologies (e.g. wind, sunlight, geothermal heat), even when such energy does not originate from a fuel in the conventional sense of the word.

4.1 Fuel Price Risk in Electricity Contracts

4.1.1 Fuel Price Risk Fundamentals

A party's exposure to fuel price risk in an electricity contract depends on three factors: (1) the variability of the fuel's price, (2) the *allocation* of fuel price risk between the parties to the contract, and (3) the ability of a party to *mitigate* the risk to which it is exposed.

Among the fuels most commonly used to generate electricity, natural gas is the most volatile in price. Long-term electricity contracts generally treat natural gas price risk through one of three pricing mechanisms: (1) fixed prices, (2) indexed prices, or (3) "tolling" agreements.

- **Fixed-price electricity contracts** typically establish a fixed and known price per MWh of delivered electricity. Such contracts clearly allocate fuel price risk to the Seller because the Seller is responsible for selling electricity at fixed prices while simultaneously dealing with a variable fuel price stream. The Buyer presumably pays a premium for fixed-price contracts because the Seller has to manage the fuel price risk to which it is exposed, which increases the Seller's costs. If the Seller does not adequately mitigate its exposure to fuel price risk it will be more likely to default on the contract, however, so the Buyer is left with some "residual" fuel price risk (i.e. contract default risk) with fixed-price non-renewable contracts.
- **Indexed-price contracts** generally index the price of electricity to either inflation or to the cost of another commodity, for example, the cost of the fuel used to generate the electricity (Kahn 1992). When indexed-price electricity contracts are indexed to the price of the natural gas used to generate the electricity, the fuel price risk is allocated to the Buyer because the Buyer receives a variable-priced product. Although indexed-price contracts are common in the industry, the DWR did not sign any such long-term contracts. The only way the DWR could have managed its fuel price risk with an indexed-price contract would have been to use financial hedging instruments. Because the DWR was unsure of its legal authority to use financial instruments at the time it contracted for power (California State Auditor 2001), the DWR chose instead to use tolling agreements (which, as described below, allow the DWR to use physical gas supply contracts to hedge its fuel price risk exposure).
- **Tolling contracts** require the Buyer of the electricity to pay for the cost of the natural gas used to generate the electricity, and the Buyer may also have the option of providing the natural gas itself. Tolling agreements and fixed-price agreements conceptualize the service and product being provided by the Seller to the Buyer in fundamentally different ways. In fixed-price contracts, the Seller clearly sells the Buyer a product: electricity. In tolling agreements, on the other hand, the Seller is effectively providing the Buyer a service: the right to use the Seller's power plant to convert natural gas to electricity. The Seller is paid not only for the use of its facility, but also for simply being available to generate (through a reservation, or "capacity" charge). In addition, the Buyer pays for the natural gas used to generate the electricity. The risk of fuel price variability is therefore clearly allocated to the Buyer in tolling contracts. The Buyer can then choose to reduce its fuel price risk exposure through fixed-price physical gas supply contracts, gas storage, or financial hedging instruments.

In contrast to natural gas, renewable resources in general have a less-variable (or even free) fuel cost stream,[32] typically resulting in less fuel price risk for either party to an electricity contract. Hence, it is more common to have fixed-price contracts for renewable electricity than for natural gas-generated electricity.[33]

Since the use of renewable resources decreases fuel price risk for both parties to a contract, all else equal, a fixed-price renewable electricity contract is a more complete hedge against fuel price risk for the Buyer than a fixed-price contract for natural gas-generated electricity.[34] This is because the Buyer of a fixed-price gas-fired contract may still bear some residual fuel price risk through potential contract default by the Seller if natural gas prices increase, as discussed above. Experience shows that the risk of contract default or renegotiation in such cases can be significant for gas-fired contracts (EIA 2002), though the magnitude of this risk is difficult to assess with precision and therefore deserves additional analysis.

4.1.2 Fuel Price Risk in the DWR Contract Sample

The DWR hedged its exposure to fuel price risk primarily through the use of fixed-price long-term non-renewable electricity contracts.[35] These fixed-price non-renewable electricity contracts comprise 57% of the total energy DWR has contracted for through 2010 (see Table 5, below). The DWR's long-term contracts for fixed-price renewable electricity provide only 1.5% of the energy DWR contracted for over the same time period. The DWR contracted for the rest of the electricity (41% of the total) with tolling agreements.[36] These tolling agreements allow (but do not require) the DWR to hedge its natural gas price risk exposure through either physical fuel supply contracts or financial hedging instruments.[37]

Overall, we find that the DWR appears to be reasonably well protected from natural gas price volatility. The elasticity of the DWR's total cost for power from all contracts through 2010 relative to natural gas prices is only about 0.2 (that is, a 10% increase in natural gas prices would increase DWR's total cost by about 2%). This protects the DWR from large increases in costs due to natural gas price increases, but also prevents the DWR from benefiting substantially if gas prices decrease, which is perhaps more significant given that the DWR contracts were signed when natural gas prices were at record high levels.

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[32] Wind, sunlight, water, geothermal heat, and landfill gas are all renewable resources that provide "free" fuel to generate electricity (fuel collection is of course costly in all cases, but once collected the fuel is effectively free). Biomass is a renewable fuel that can either be free or have a variable cost.

[33] Coal prices are also less variable than natural gas prices, and contracts for electricity from coal-fired power plants are more often fixed-price than contracts for natural gas-generated electricity.

[34] In addition, if an increase in renewable electricity generation reduces natural gas consumption, and this reduction has even a marginal effect on natural gas prices, the overall economic benefit to consumers could be quite large, given the enormous volume of natural gas consumed throughout the economy (Nogee 1999).

[35] 45% of the DWR's total electricity supply is from fixed-price natural gas-generated electricity contracts, and 12% is from fixed-price contracts for power that do not specify the resources that are used to generate the electricity; these "unspecified" contracts will most likely use non-renewable resources (primarily natural gas) to generate the electricity to be provided under the contract.

[36] Several of the DWR's renegotiated contracts were converted from fixed-price to tolling contracts, increasing the DWR's fuel price risk exposure.

[37] After January 2003, the state's three investor-owned utilities will hold the responsibility to manage the fuel supply and hedging arrangements for the DWR contracts.

Table 5. Key Contract Terms that Allocate Fuel Price Risk in the DWR Long-term Contracts

Seller	Pricing Structure	Resource	Dispatchable?	Ten-year Energy Purchases (GWh)‡
Allegheny	Fixed	Natural gas	No	63,898
Calpine – 2	Fixed	Natural gas	No	70,115
Calpine – 3	Fixed	Natural gas	Yes	8,001
Dynegy – 1	Fixed	Natural gas	No	14,246
High Desert	Fixed	Natural gas	No	51,896
Williams	Fixed	Natural gas	No	56,535
		Total Fixed-Price Natural Gas Contracts		**264,691 (45%)**
Calpine – 1	Fixed	Unspecified	No	64,596
El Paso	Fixed	Unspecified	No	2,441
Morgan Stanley	Fixed	Unspecified	No	2,136
		Total Fixed-Price Unspecified Resource Contracts		**69,174 (12%)**
		Total Fixed-Price Non-Renewable Contracts		**333,865 (57%)**
Alliance Colton	Tolling	Natural gas	Partially	1,468
Calpeak	Tolling	Natural gas	Yes	5,027
Calpine – 4	Tolling	Natural gas	Yes	3,024
Coral Power	Tolling > 2005	Natural gas	Partially	28,677
Dynegy – 2	Tolling	Natural gas	Partially	21,174
Fresno Cogeneration	Tolling	Natural gas	Yes	950
GWF Energy	Tolling	Natural gas	Yes	23,713
PacifiCorp	Tolling > 2002	Natural gas	Yes > 2002	21,900
Sempra	Tolling > 2002	Natural gas	No	93,325
Sunrise	Tolling	Natural gas	Yes	38,888
Wellhead	Tolling	Natural gas	Yes	4,047
		Total Natural Gas Tolling Contracts		**242,194 (41%)**
Capitol Power	Fixed	Biomass	No	590
Clearwood	Fixed	Geothermal	No	1,692
County of Santa Cruz	Fixed	Landfill Gas	No	112
Imperial Valley	Fixed	Biomass	No	362
PG&E Energy Trading	Fixed	Wind	No	2,017
Soledad	Fixed	Biomass	No	410
Whitewater	Fixed	Wind	No	3,263
		Total Fixed-Price Renewable Contracts		**8,448 (<1.5%)**
			TOTAL	**584,506 (100%)**

Note: only DWR contracts signed before October 2001 and with terms of three years and longer are included in this table. A number of these contracts have subsequently been renegotiated; the "final" contract terms are not reflected in this table. Totals may not equal sum of components due to independent rounding.
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001).

Although the elasticity of the DWR contract costs to natural gas prices is relatively low, it deserves note that the absolute amount of money at stake is quite large. The State Auditor estimates the total cost of the DWR's long-term contracts to be $40.3 billion over ten years (see Table 2, in Section 3). The Auditor used the DWR's natural gas price forecast to calculate the total cost of the DWR contracts. The DWR's natural gas price forecast at the time anticipated gas prices that are significantly higher overall than the CEC's forecast at the time (see Appendix C).[38] Using the Auditor's model of the DWR contracts with the CEC forecast of natural gas prices, the DWR long-term contracts would cost approximately $38.3 billion – $2 billion less than the Auditor's estimate, or 0.85 cents less per each kWh delivered by tolling agreements.

Since the contracts were signed, natural gas prices have been reasonably low (at least until the winter of 2002/2003, when prices again rose substantially). If the DWR (or the three investor-owned utilities, which received operational control over the DWR contracts in January 2003) does not choose to hedge its natural gas price risk exposure through either physical fuel supply contracts or financial hedging instruments, the state could potentially face significant cost increases in the future. For example, if we use the CEC natural gas price forecast but assume that gas prices spike during 2006 to the levels gas prices reached in 2001, the relative increase in gas prices could cost the state $1.7 billion, or 0.7 cents per each kWh delivered by tolling agreements (see Appendix C).

Finally, because the DWR chose to mitigate its fuel price exposure primarily by signing long-term fixed-price gas contracts, and not by purchasing sizable quantities of renewable electricity, the state is exposed to some residual fuel price risk due to the possibility of contract default were natural gas prices to rise precipitously. For example, if the Seller is exposed to extremely high natural gas prices and can no longer meet its contractual obligations, the DWR will be left to find a replacement contract at a time when gas prices are high. The magnitude of this risk is difficult to assess.

Additional details on the DWR's approach to fuel price risk allocation and mitigation is offered below; we discuss the DWR's non-renewable fixed-price contracts, natural gas tolling contracts, and renewable fixed-price contracts, in turn. Readers not interested in this detail will lose little by skipping to Section 4.2.

A. Non-Renewable Fixed-Price Contracts

As noted above, 57% of the electricity DWR originally contracted for over the next decade is from fixed-price contracts with non-renewable (primarily natural gas) resources (subsequent contract renegotiations have lowered this number somewhat). All of these fixed-price contracts allocate fuel price risk to the Seller, in principal leaving the state unaffected by changes in the underlying cost of fuel, unless contract defaults occur.

[38] The DWR's natural gas price forecast was created by its consultant in July 2001, when gas prices were still extremely high. The CEC forecast was published in February 2002.

B. *Natural Gas Tolling Contracts*

Over the next decade, 41% of the electricity DWR originally contracted for is expected to come from natural gas tolling agreements.[39] These contracts allocate natural gas price risk to the DWR and the state. The contract price in most of these tolling agreements consists of: (1) a capacity charge that is largely independent of the plant's actual generation of electricity; (2) a fuel charge based on the amount of fuel used to generate electricity (if the Seller is providing fuel); and (3) an operations and maintenance (O&M) charge per MWh of electricity generated. Some contracts have other charges including a fixed O&M charge (independent of whether or not the plant generates power), and charges for fuel used to start-up the plant.

Tolling agreements allow the Buyer to choose the level of natural gas price risk exposure it desires. The tolling contracts give the DWR the option to either supply the natural gas itself,[40] or to approve a fuel supply plan for the Seller to supply the gas. Hence, the DWR can manage its fuel price risk by either signing a long-term contract for natural gas supply, agreeing with the Seller on a fuel supply plan that meets the DWR's risk exposure needs, or else purchasing natural gas on the spot market and using financial instruments to hedge the price volatility.

If the DWR does not hedge the natural gas price risk it is exposed to through its tolling agreements, the DWR's total cost for power over ten years could vary on the order of $2 billion, as discussed above. If the DWR instead chooses to hedge its natural gas price risk, it will have to bear the cost of hedging. There are numerous financial hedging instruments (e.g. futures, swaps, and options) and physical hedging instruments (e.g. fixed-price gas supply contracts and storage) that the DWR could use to mitigate its fuel price risk exposure. Bolinger et al. (2002) tentatively find that the cost of hedging on a long-term basis with these instruments is on the order of $5 per MWh.

Although the DWR bears fuel price risk in all of the tolling contracts, almost all of the tolling agreements in our sample allow the DWR to dispatch the power plant. (All but one of the tolling contracts are at least partially dispatchable, and all but one of the fixed price contracts are non-dispatchable, see Table 5, above.) In effect, under a tolling agreement with a dispatchable plant, the DWR accepts fuel price risk in exchange for a reduction in its demand risk. The link between tolling and dispatchability is consistent with the desire of a Seller to avoid excessive fuel price risk – it would be risky for a Seller to agree to provide fixed-price energy and to let the DWR dispatch the facility, because the uncertain amounts of fuel required to generate power would make it difficult for the Seller to mitigate its fuel price risk exposure.[41]

[39] This assumes that the DWR takes the maximum quantity of electricity under the contracts, including the dispatchable contracts, an admittedly aggressive assumption.
[40] The contracts in the DWR sample vary in the frequency with which the Buyer has the opportunity to choose to supply the fuel itself, but it is most commonly once per year.
[41] A more modest fuel price risk involves the allocation of fuel imbalance charges. When a power plant is dispatchable, it may draw more or less fuel from a natural gas pipeline than it was scheduled to, resulting in fuel imbalance charges. Seven of the eleven tolling agreements specify that fuel imbalance charges will be paid by the party at fault for incurring them. One tolling contract requires the Buyer to pay for all imbalance charges, while the only non-dispatchable tolling agreement requires the Seller to pay for fuel imbalance charges. Two other tolling contracts do not specify the allocation of fuel imbalance charges.

C. Renewable Fixed-Price Contracts

Although renewable energy contracts can provide the most complete hedge of fuel price risk possible, the DWR did not choose to use renewables to hedge its fuel price risk to any large extent. The DWR's original long-term contracts for renewable energy comprise just 1.5% of the energy DWR has contracted for over the next decade. Reflecting the largely fixed (or zero) fuel cost for renewable facilities, all of the DWR's contracts for renewable electricity are fixed price.

Of the renewable energy DWR originally contracted for, 84% will be generated from "free" renewable fuels (wind, geothermal heat, and landfill gas). These contracts provide the greatest possible mitigation of fuel price risk for both the DWR and the Sellers. For the DWR, the mitigation of fuel price risk provided by these renewable electricity contracts is greater than the mitigation provided by the fixed-price natural gas contracts, because of the default risks described earlier. The renewable contracts are also a more complete hedge against fuel price risk than a physically or financially hedged tolling agreement, since counterparties to such financial instruments may not always honor their commitments. In sum, these renewable electricity contracts *reduce* fuel price risk for both parties, whereas hedged natural gas contracts simply *shift* fuel price risk to other parties.

The other 16% of the DWR's renewable electricity is to be generated from biomass resources. Unlike the other renewable fuels, biomass is not always "free" to the generator and can have a variable price. Since the DWR's biomass contracts are fixed-price, the Sellers bear the biomass price risk. Similar to the fixed-price natural gas contracts, the DWR still bears some residual fuel price risk (i.e., contract default risks) in the biomass contracts.

Biomass contracts have at least one advantage and one disadvantage compared to natural gas contracts, with respect to fuel price risk. Since fuel supply for biomass power plants is local by nature (it is not economical to transport biomass over long distances), the volatility of biomass prices is less systematic than natural gas prices – that is, a spike in biomass prices at one plant will not necessarily affect the price of fuel for all biomass generators in the state simultaneously. On the other hand, there is no index price for biomass, which makes it difficult to hedge biomass price risk with financial instruments; the Seller's only option is to use physical hedges (i.e., long-term, fixed-price biomass fuel supply agreements) to mitigate its fuel price risk exposure.

4.2 Fuel Supply Risk in Electricity Contracts

4.2.1 Fuel Supply Risk Fundamentals

The ability of a power plant to reliably generate electricity depends, in part, on the dependability of its supply of fuel. Non-renewable and renewable power plants face different challenges in obtaining reliable supplies of fuel.

The reliability of the supply of natural gas to a power plant depends on both the reliability of the supply of the gas itself, and the reliability of the transportation of the gas to the plant. The supply of natural gas to a power plant can be interrupted due to "normal" supply and transportation constraints (e.g. pipeline constraints), or due to catastrophes. The parties to an electricity contract can usually manage the risk of a "normal" natural gas supply or transportation constraint by requiring firm fuel and transportation contracts. (In certain circumstances, however, even firm natural gas contracts may be interrupted (CEC 2000), but these events are generally foreseeable.[42]) On the other hand, the risk of a catastrophic interruption of natural gas supply to a power plant (e.g. an attack on the pipelines that bring gas into California) cannot be readily reduced through the terms of an individual contract. From the perspective of maintaining a reliable supply of electricity in California (rather than the perspective of the two parties to an individual contract), the risk of a catastrophe is much more serious than a "normal" gas supply or transportation constraint, because it is unpredictable and systematic – it affects numerous power plants simultaneously – potentially causing widespread disruptions to the electricity grid.

Contracts for electricity generated from natural gas at individual power plants cannot do much to reduce the risk of fuel supply uncertainties, other than requiring a firm gas supply and transportation contract. Consequently, contracts for electricity mostly *allocate* the remaining risk of a fuel supply interruption rather than further *reducing* the risk. Individual electricity contracts also cannot manage the more serious *systematic* risk of a catastrophic natural gas supply interruption (that would affect numerous power plants at once); this risk can only be managed by the owner of a portfolio of electricity supplies, for example, through resource diversification.

The supplies of many renewable fuels used to generate electricity are less predictable, on a day-to-day basis, than the supply of natural gas.

- Solar and wind resources have a significant amount of hourly, daily, seasonal, and even annual variation that is difficult to predict accurately in advance. Individual contracts for electricity from solar and wind resources generally cannot reduce fuel supply risk without using back-up generation or storage.[43]
- Landfill gas and geothermal resources have less day-to-day variation than solar and wind resources, but their supply can be unpredictable over longer time scales.
- Hydroelectric power has a relatively predictable and controllable fuel supply; water for hydroelectric power varies seasonally and from year-to-year, but water can be stored behind dams to smooth out some of the variation.[44]
- Biomass power plants are the only type of renewable facilities whose fuel is not provided naturally to the plant – biomass plants have to acquire and transport fuel to the plant, which introduces an additional source of uncertainty. Biomass electricity contracts can manage fuel supply risk in a similar manner to natural gas contracts, by acquiring firm fuel and transportation contracts from biomass suppliers.

[42] For example, in 1999 and 2000, the natural gas infrastructure in the San Diego area began to reach the limits of its capacity, and San Diego Gas and Electric petitioned the CPUC to request permission to curtail firm fuel service to several power plants (CEC 2000).
[43] It may be possible to manage this risk financially using weather derivatives, but the risk cannot be managed in terms of physical reliability.
[44] It is possible to store biomass, hydro, and landfill gas resources to reduce fuel supply uncertainties. Of course, it is also possible to store natural gas.

In some cases renewable fuel supply variability is systematic, for example, cloudy weather can reduce solar energy production on a statewide basis. In contrast to natural gas fuel supply risk, however, the risk of renewable fuel supply uncertainty is frequently unsystematic – affecting individual renewable plants or resource areas – rather than systematic and affecting all plants simultaneously.

4.2.2 Fuel Supply Risk in the DWR Contract Sample

The DWR bears some fuel supply risk in all of the DWR's non-renewable and renewable long-term (three years and longer) contracts. As discussed below, the DWR bears the risk of a catastrophe (e.g. a natural gas pipeline explosion) in all of the non-renewable contracts. The DWR also bears the risk of other, less dramatic fuel supply or fuel transportation interruptions in most of the non-renewable contracts. Since the DWR contracts increase California's overall reliance on natural gas, the contracts may actually increase the state's systematic risk of a natural gas supply interruption – affecting numerous power plants simultaneously – making the electrical grid more vulnerable to natural gas interruptions.

Renewable contracts may help diversify the DWR's fuel supply portfolio and thereby decrease the risk that a systematic natural gas supply interruption will disrupt California's electrical grid.[45] Nonetheless, in the DWR's renewable contracts, day-to-day variations in fuel supply are a larger concern than in the natural gas contracts. Historically, renewable energy has often been sold on an "as-available" basis regardless of the specific renewable energy source.[46] The DWR's wind power contracts continue this trend in offering as-available supply and therefore the Buyer must manage considerable hourly, daily, and seasonal supply variations. Contracts for electricity from other renewable resources do not have as variable a fuel supply (e.g. biomass), however, and can therefore provide for a firmer supply of electricity.

We begin by examining fuel supply risk in the DWR's non-renewable fixed-price contracts, followed by the non-renewable tolling contracts, and then finally the renewable contracts.

A. Non-Renewable Fixed-Price Contracts

In the DWR's fixed-price non-renewable contracts, the Seller is responsible for procuring the fuel supply and fuel transportation necessary to generate the electricity to be provided under the contract. Almost none of these contracts explicitly allocate the risk of a fuel supply or transportation interruption; as such, the allocation depends primarily on the definition of force majeure. An event of force majeure is defined in the EEI contract template as a circumstance that prevents a party from performing its obligations, that is not within the reasonable control of (or the result of negligence of) the party, and which the party cannot overcome by the exercise of due diligence. During an event of force majeure, the Seller is excused from delivering power.

Fifty-seven percent of the DWR's non-renewable energy is under fixed-price contracts. Of these, the Calpine – 2 contract is the only fixed-price non-renewable contract that explicitly

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[45] A systematic fuel supply interruption would have large economic repercussions, so although the probability of a systematic interruption may be small, there may be considerable value in reducing the risk.
[46] As-available contracts allow the power plant to sell electricity whenever it is able to generate it.

allocates the risk of a fuel supply or fuel transportation interruption to the DWR. The Calpine – 2 contract provides that a fuel supply or transportation interruption is an excused outage, except if the interruption is due to curtailment under an interruptible gas transportation contract, and firm gas transportation is available.[47]

Although the other fixed-price contracts do not explicitly allocate the risk of a fuel supply or fuel transportation interruption, they presumably allocate the risk in a similar manner to the Calpine – 2 contract. The fixed-price contracts excuse the Seller from providing power – through the force majeure clause – if a fuel interruption is out of the Seller's control, and not due to negligence. If the Seller has firm fuel supply and transportation contracts that are interrupted, the outage would be excused and the Seller would face no penalty. However, if the Seller has an interruptible fuel supply or transportation contract that is interrupted, the outage would presumably *not* be excused, the Seller would have to pay for the DWR's incremental cost of purchasing replacement power ("cover damages"), if any, and the Seller would be penalized according to the contract's availability requirements.[48]

The three fixed-price contracts that do not specify the resources that will be used to generate the electricity[49] are also the only electricity supply contracts that do not specify what specific generating facilities will be used. In these cases, it may be more difficult for the Seller to claim force majeure for a fuel supply or fuel transportation interruption to an individual plant (e.g., if a gas pipeline to the plant is crippled), since the contract does not specify from what generating units the Seller will supply power.

B. Natural Gas Tolling Contracts

The firmness of both fuel supply and fuel transportation arrangements are important in determining the reliability with which a power plant can generate electricity. All of the DWR's tolling contracts give the DWR the option to either (1) supply the natural gas needed to generate the electricity under the contract, or (2) approve a fuel supply plan for the Seller to supply the gas. Six of the eleven natural gas tolling contracts assign to the Seller the responsibility of procuring natural gas transportation; three of these six contracts require the Seller to arrange for firm fuel transportation, while the other three allow the fuel transportation to be interruptible. The other five tolling contracts do not assign responsibility for obtaining fuel transportation. It is possible that a fuel supply plan (agreed to by the parties) would determine the fuel transportation arrangements.

Similar to the fixed-price non-renewable contracts, the DWR's tolling contracts allocate much of the fuel supply risk to the DWR. Nine of the DWR's eleven natural gas tolling contracts explicitly excuse the Seller from delivering power if the fuel supply or fuel transportation to the plant is interrupted. (Some of these contracts are more lenient than others; see Table 6, below.)

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[47] Interruptible natural gas contracts allow the distributing company to curtail service under certain circumstances, as specified in the contract, whereas firm contracts provide continuous service.
[48] For further discussion of cover damages and availability guarantees, see Section 5.4.2 on Performance Risk.
[49] The Calpine – 1, El Paso, and Morgan Stanley contracts do not specify the resources that will be used to generate electricity; these "unspecified" contracts will most likely use non-renewable resources (primarily natural gas) to generate the electricity to be provided under the contract, and are therefore included in this section.

If a contract does not explicitly address the risk of a fuel supply or fuel transportation interruption, then the allocation of the risk is determined by the contract's force majeure clause, as discussed above.

Unlike the fixed-price non-renewable contracts, however, only three of the tolling contracts require the Seller to pay the DWR cover damages if the Seller has an unexcused outage due to a fuel interruption.[50] That said, most of the tolling agreements penalize the Seller for not meeting availability requirements; for the most part, the contracts require availabilities of over 95% during the summer and over 90% during the rest of the year (see Table 6, below).[51]

Table 6. Key Contract Terms that Allocate Fuel Supply Risk in the DWR Natural Gas Tolling Contracts

Seller	Type of fuel transportation arrangement Seller must make	Is Seller excused from delivering power if fuel supply or fuel transportation is interrupted?	Availability Requirement
Alliance Colton	Not addressed explicitly	Yes	June through October: 95%
Calpeak	Firm	Yes, if interruption is due to non-economic reasons.	June – October, December – February: 96% Otherwise: 94%
Calpine – 4†	Not addressed explicitly	Yes	June through October: 98% Otherwise: 92%
Coral Power	Not addressed explicitly	Not addressed explicitly	July, August, September: 97% Otherwise: 94.3%
Dynegy – 2	Firm	Yes	None
Fresno Cogeneration	May be interruptible	Yes, except if Seller has firm transportation contract and interruption is due to Seller's negligence.	June through October: 97% Otherwise: 94%
GWF Energy	May be interruptible	Yes, except if Seller has firm transportation contract and interruption is due to Seller's negligence.	June through October: 98% Otherwise: 94%
PacifiCorp	Firm	Yes, if interruption is due to force majeure in fuel supply or transportation agreement.	Approx. 88%
Sempra†	Not addressed explicitly	Yes	None
Sunrise	Not addressed explicitly	Not addressed explicitly	June through September: 95% Annual: 91.8%
Wellhead	May be interruptible	Yes, except if Seller has firm transportation contract and interruption is due to Seller's negligence.	June through October: 97% Otherwise: 94%

Note: some of these contracts have subsequently been renegotiated
† Seller pays DWR cover damages for unexcused outages

[50] The Calpine – 4, Sempra, and Sunrise contracts require the Seller to pay cover damages for an unexcused outage.
[51] In dispatchable agreements, availability is generally defined as the number of hours during the period that the unit was *available* to deliver energy divided by the total possible dispatch hours during the period. (See Section 5 on Performance Risk for further discussion of availability.)

C. *Renewable Fixed-Price Contracts*

The DWR contracted for electricity from four different renewable resources: wind, geothermal, landfill gas, and biomass. Each of these resources faces different challenges with regards to fuel supply variability. In all but one of the DWR's renewable contracts, however, the DWR bears some fuel supply risk.

- The **wind** contracts provide the DWR with electricity "as-available," or whenever there is wind available to generate electricity. Since the contracts are fixed price and the Seller is only paid when electricity is delivered to the DWR (i.e., there is no capacity payment), the parties share the fuel supply risk – the DWR's supply of electricity is uncertain, and the Seller's revenue stream is uncertain.

- Although the **geothermal** contract is unit-contingent,[52] and therefore more firm than an as-available contract, it has clauses that make it similar to an as-available contract. Problems with the geothermal steam-field are considered to be an excused outage, and inadequate or excessive geothermal reservoir pressures or temperatures constitute events of force majeure, also excusing the Seller from delivering power. Although these clauses shift some of the fuel supply risk to the DWR, the geothermal contract requires the Seller to operate the plant such that the monthly actual generation is within plus or minus 10% of the monthly scheduled generation, making it somewhat "firmer" than an as-available contract.[53] Hence, as with the wind contracts, the parties share the fuel supply risk in the geothermal contract, though the geothermal contract allocates relatively more of the fuel supply risk to the Seller through the requirement that the Seller operate the facility within a certain output range.

- The **landfill gas** contract is a unit-contingent contract, and therefore excuses the Seller from delivering power whenever the plant is unavailable due to an outage. The Seller is required, however, to generate power at the plant's "maximum capability" in every hour, and to operate the plant such that the monthly actual generation is within plus or minus 10% of the monthly scheduled generation. Generating plant "outage" and "maximum capability" are not defined in the contract, but it is likely that a fuel supply interruption would excuse the Seller from providing power, while worsening the Seller's availability. The amount of fuel supply risk the DWR has to bear is constrained by the Seller's availability requirement: 75% availability during June through October, and 70% otherwise.[54] If the Seller does not meet the availability requirement for three consecutive months, the DWR can terminate the contract. (This is the DWR's only remedy with regard to the plant's availability.) The parties therefore share the fuel supply risk in the landfill gas contract, but the DWR bears less risk than in either the wind or the geothermal contracts.

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[52] Unit-contingent contracts excuse the Seller from delivering scheduled power during forced outages and events of force majeure. For a further discussion of unit-contingent and firm electricity contracts, see Section 5 on Performance Risk.

[53] The geothermal contract has no availability requirement per se, but the contract states that the plant is expected to generate power 8,000 hours per year (91% availability).

[54] In the renewable contracts, availability is generally defined as the number of hours the plant delivers power during the period divided by the total possible number of hours the plant could have delivered power during the period.

- The **Soledad biomass** contract has a nearly identical allocation of fuel supply risk (and an identical availability requirement) as the landfill gas contract; the **Capitol Power biomass** contract is also nearly identical, but the fuel supply risk that the DWR must bear is further reduced by a requirement that the Seller obtain firm commitments for fuel supply and fuel transportation (see Table 7, below).[55]

  The availability requirements in these three renewable contracts (the landfill gas, and two biomass contracts) do not reflect the availability the plants are capable of, or the availability they are expected to achieve. Instead, the availability requirement represents the "last straw" – the point where DWR can terminate the contract. This is in contrast to the non-renewable contracts discussed above, which penalize the Seller monetarily for not meeting an availability requirement (that the plant is expected to achieve), but do not set a minimum level of availability beyond which the DWR can terminate the contract.

- The **Imperial Valley biomass** contract is the firmest of the renewable contracts. In fact, the contract may even be firmer than most of the non-renewable contracts, because the contract explicitly excludes the loss of fuel supply from the definition of force majeure. (An event of force majeure is the only excused outage under the contract.) Similar to the fixed-price non-renewable contracts, the Imperial Valley biomass contract requires the Seller to pay cover damages to the DWR if the Seller fails to deliver power due to an unexcused outage.

As a whole, the DWR's renewable electricity contracts allocate a significant amount of fuel supply risk to the DWR (see Table 7, below, for further details). These contracts, however, vary considerably in how much of the fuel supply risk is allocated to the DWR. The Imperial Valley contract makes it clear that in some cases it is possible to contract for firmer supplies of renewable electricity than the DWR chose.

[55] The landfill gas contract and the Soledad biomass contract are expected to generate power 8,000 hours per year (91% availability). The Capitol Power biomass contract is expected to generate power 7,680 hours per year (88% availability).

Table 7. Key Contract Terms that Allocate Fuel Supply Risk in the DWR Renewable Electricity Contracts

Seller	Renewable Resource	Contract clauses relevant to fuel supply risk	Firmness	Availability Requirement
Capitol Power	Biomass	▪ Seller must have firm commitments for fuel supplies and transportation. ▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 105% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	Unit-Contingent	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate. ▪ (Plant expected to deliver 7,680 hours per year; 88% availability)
Clearwood	Geothermal	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 120% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	Unit-Contingent (Force majeure includes inadequate or excessive geothermal reservoir pressures or temperatures)	▪ None (Plant expected to deliver 8,000 hours per year; 91.3% availability)
County of Santa Cruz	Landfill gas	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 105% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	Unit-Contingent	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate. ▪ (Plant expected to deliver 8,000 hours per year; 91.3% availability)
Imperial Valley	Biomass	▪ DWR must take (Seller must deliver) the quantity of energy established in the contract.	Firm (Force majeure does not include loss of fuel supply.)	▪ None (Seller pays cover damages to DWR if Seller fails to deliver.)
PG&E Energy Trading	Wind	▪ Electricity is generated when sufficient wind is available.	As-available	▪ None
Soledad	Biomass	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	Unit-Contingent	▪ June through October: 75% Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate. ▪ (Plant expected to deliver 8,000 hours per year; 91.3% availability)
Whitewater	Wind	▪ Electricity is generated when sufficient wind is available.	As-available	▪ None

Note: Several of these contracts have been renegotiated somewhat, and at least one has been terminated.

4.3 Summary of Fuel Price and Supply Risk

An increase in the price of natural gas was one of the root causes of California's electricity crisis. The DWR subsequently protected itself from fuel price risk primarily through the use of fixed-price non-renewable contracts, which will provide about 57% of the energy DWR has contracted for over the next decade. This makes clear that some degree of price stability can be achieved through fixed-price contracts with natural gas generators by shifting price risks to the Sellers. If the state wants to further mitigate potentially large increases in costs due to future natural gas price spikes, the state will have to bear the cost of hedging its fuel price risk in the natural gas tolling contracts as well, because these contracts shift fuel price risks to the Buyer.

In contrast to the volatility of natural gas prices, most of the renewable energy DWR contracted for has a "free" source of fuel. Not surprisingly, all of the DWR's long-term renewable contracts shield the DWR from fuel price risk by offering fixed prices. These renewable contracts also provide the DWR with a more complete hedge against fuel price risk than the non-renewable contracts due to residual fuel price – or contract default – risk in the natural gas contracts.[56] Regardless of the merits of renewable energy in mitigating fuel price risk, however, the DWR did not take advantage of the opportunity to use long-term renewable contracts to stabilize its costs to any significant extent: only 1.5% of its contracted electricity is derived from renewable sources.

The DWR's contracting decisions undoubtedly involved trade-offs between fuel price risk and fuel supply risk. Natural gas-fired power plants and renewable generation facilities face different challenges in maintaining a reliable supply of fuel to ensure the reliable and predictable production of electricity. Natural gas-fired power plants are more vulnerable to catastrophic interruptions in fuel supply (affecting many plants simultaneously), while certain renewable generating facilities are more vulnerable to unsystematic hourly, daily, monthly, or annual variability in fuel supply.

These fundamental characteristics are reflected in the DWR contracts. In particular, DWR's renewable contracts vary considerably in how much of the fuel supply risk is allocated to the DWR, depending in part on the renewable resource itself. For example, the wind contracts offer as-available supply, while one of the biomass contracts offers firm supply. "Normal" fuel supply risks are far more likely to be allocated to the Seller in the natural gas contracts, shielding the state from some supply risk. Individual electricity contracts cannot effectively mitigate "systematic" risks, however; the owner of a portfolio of electricity supplies must manage systematic fuel supply risks through the design of their portfolio of fuel supplies. Accordingly, the DWR's natural gas contracts allocate the risk of catastrophic failures in the natural gas supply infrastructure to the state.

[56] There may be a risk of bankruptcy among renewable providers, however, in most cases it would be unrelated to fuel price risk.

5 Performance Risk in Electricity Contracts

Contracts create a set of requirements to which each party to the contract agrees to adhere. This section addresses performance risk, defined here as the risk that the supplier may not be willing or able to deliver electricity according to the contractually prescribed requirements in terms of time and quantity.[57] Of all the risks addressed in this paper, the parties to an electricity contract are most able to control and mitigate performance risk. As a result, contracts contain numerous clauses designed to manage performance risk.

To the extent that renewable generation is based on a variable underlying fuel stream (e.g., wind), some renewable contracts clearly cannot have the same requirements for energy delivery as a contract for natural gas-fired generation. These issues of dispatchability, controllability, and predictability are discussed later under the Demand Risk in Section 6. In the present section we define performance risk more narrowly, and examine the more limited and mundane clauses that penalize or encourage parties to a contract to meet their contractually determined delivery requirements, whatever they might be.

5.1 Performance Risk Fundamentals

Our analysis of performance risk is divided into two periods: (1) during the construction of a power plant, and (2) during the operation of a power plant. The major sources of uncertainty during the construction of a power plant are whether the plant will be built on time, and whether the plant will be built within budget.[58] The major sources of uncertainty during the delivery period of an electricity contract (once a power plant is operational) are how efficiently the power plant will be operated, and how reliably the generator will supply the amount of energy or capacity that was contracted for.

Electricity contracts attempt both to *reduce* performance risk, and to *allocate* whatever performance risk remains between the parties to the contract. Since many elements of performance risk are within the control of the generator, electricity contracts contain numerous penalties and incentives to reduce performance risk – that is, to ensure that a plant is constructed and operated in a desirable fashion, and to ensure that the generator performs according to the terms of the contract. If a contract does not contain specific remedies to address non-performance, and one party to a contract does not perform according to the terms of the contract, the only remedy of the other party may be to declare the non-performing party in default and to terminate the contract;[59] this rather drastic action might be appropriate if the non-performing

[57] Another side of performance risk exists: the risk that the Buyer will not take or pay for the power under the contract. This risk is discussed to some degree under Regulatory Risk, later in this paper, but is not otherwise covered in this chapter.

[58] Power plant developers have experienced large cost over-runs and construction delays in the past; possibly the most notorious example in California is PG&E's Diablo Canyon nuclear power plant, which was expected to cost $300 million to build, but ended up finally reaching commercial operation more than 10 years behind schedule at a total cost of over $5 billion (Hirsch 1999).

[59] The EEI template contract provides that a party defaults on a contract if the party fails to perform a material covenant contained in the contract. The defaulting party is required to pay the non-defaulting party a termination payment, equal to the difference between the present value of the existing contract and a replacement contract.

party's transgression is serious, but would not provide a satisfactory remedy for minor infractions.

The allocation of performance risk during the delivery period of a contract is managed in part by the "firmness" of the contract, which determines under what circumstances the Seller is excused from delivering electricity. In the DWR sample, all contracts are for either "unit-contingent" or "firm" electricity products (some of the renewable contracts are "as-available", which can be viewed as a particularly lenient unit contingent contract). Unit-contingent contracts excuse the Seller from performing in more situations than firm contracts, which only excuse the Seller during events of force majeure.

A unit-contingent contract, as defined in the EEI contract template, excuses the Seller from delivering power when the Seller's specified generating facilities are unavailable either due to a forced outage,[60] or to an event that was not anticipated as of the date the contract was executed, and that is not within the reasonable control of (or due to the negligence of) the Seller. Both unit-contingent and firm contracts excuse the Seller's performance during an event of force majeure. An event of force majeure is defined in the EEI contract template as a circumstance that prevents a party from performing its obligations, that is not within the reasonable control of (or the result of negligence of) the party, and which the party cannot overcome by the exercise of due diligence. Force majeure is commonly used in legal contracts to absolve parties of responsibility during catastrophes, which are usually defined as acts of God, natural disasters, and other "unforeseeable and irresistible" events (Tepper 1995); however, some contracts expand on the definition of force majeure. The definition and interpretation of force majeure clauses can strongly influence the amount of performance risk that each party to a contract bears.

5.2 Performance Risk in the DWR Contract Sample

The DWR's *non-renewable* contracts are of two types: dispatchable and non-dispatchable. A non-dispatchable contract usually delivers electricity according to a fixed schedule specified in the contract, while a dispatchable contract allows the DWR to decide when it wants the Seller's power plant to produce electricity on an ongoing basis (within some limitations). (Dispatchability is discussed further in Section 6 on Demand Risk.) In most cases, the DWR's dispatchable contracts are natural-gas tolling agreements, while the non-dispatchable contracts offer fixed-prices. The DWR's *renewable* energy contracts are all non-dispatchable. Because dispatchable and non-dispatchable contracts provide different products to the DWR, the DWR must manage different types of performance risk under each contract type.

As discussed in more depth below, we find substantial differences in how performance risks are handled between the DWR's dispatachable and non-dispatchable contracts (regardless of the generating source). Much more subtle differences exist between the non-dispatchable renewable and non-renewable contracts. While some sources of renewable generation are clearly held to different and lower delivery standards than are natural gas plants (see Section 6 about Demand Risk), we find that the treatment of performance risk in the renewable contracts is similar to

[60] A forced outage is defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines as an outage resulting from an immediate mechanical, electrical, or hydraulic control system trip or an operator-initiated trip in response to an alarm.

(though somewhat more lenient than) the treatment of those same risks in the non-renewable, non-dispatchable contracts (most of which are natural gas).

Overall, we find that the DWR's long-term electricity contracts provide for the construction of a significant amount of new generation capacity in California, while exposing the DWR to only a minimal amount of the risk of construction cost over-runs, as shown below. Although the Sellers of the contracts bear nearly all of the risk of construction cost over-runs, the DWR bears some of the risk that the new power plants will not be built on schedule or even completed at all. This is true for both the renewable and the natural gas contracts, though as noted below the renewable contracts, on average, appear to shift a greater degree of the risk to the DWR.

One of the principal ways DWR's exposure to performance risk has been reduced is as a result of high contract prices; the high prices give the Sellers an inherent incentive to deliver power in order to earn profitable payments. Of course, from a Buyer's perspective, high prices are not an optimal way to encourage performance.

The DWR contracts also contain numerous other provisions to reduce performance risk during the delivery period of the contracts. Availability guarantees and penalties are the primary ways that performance risk is managed in the DWR's dispatchable natural-gas contracts, whereas the non-dispatchable contracts primarily use "cover damages" – a penalty equal to the incremental cost of replacement power for undelivered energy – to reduce performance risk. Most contracts also require the Sellers to maintain the power plants in accordance with "prudent industry practices." The renewable contracts appear, on average, to be afforded somewhat more lenient terms when it comes to performance risk. For example, the DWR assumed additional performance risk in the two wind contracts by agreeing to bear any ISO imbalance charges that might arise. [61]

5.2.1 Performance Risk During Construction of a Power Plant

A. Non-Renewable Contracts

Over half of the DWR's original non-renewable contracts provide for the construction of new natural-gas power plants, and perhaps not surprisingly all but one of these contracts allocates the risk of construction cost overruns to the Seller. This is typical of power purchase contracts. The Sunrise contract is the only one that requires the Buyer to share in some of this risk, and it does so by increasing the DWR's capacity charge if the actual construction costs exceed the estimated costs, and vice versa. Such contract terms, if designed poorly, can impose substantial risk on the Buyer by providing skewed incentives to the Seller to control costs.

In all of the DWR's non-renewable contracts that require new construction, the parties share the risk that a new natural-gas power plant will not be built on schedule; if a power plant's operation is delayed, the Seller's revenue stream will be delayed and the DWR may have to procure replacement energy. In most of these contracts, the DWR may terminate the contract (i.e.,

[61] The California State Auditor (2001) expressed concern that many of the DWR contracts contain performance risk terms that are excessively lenient towards the Sellers, as discussed in this chapter. Partly in response to the Auditor's report, many of the DWR's renegotiated contracts contain stronger performance risk terms.

relieve both parties of any further obligation) if the new natural-gas plant does not reach commercial operation by a specified deadline (see Table 8, below). Some contracts also financially penalize the Seller for not meeting construction deadlines,[62] and a few contracts provide the Seller with a financial incentive to reach commercial operation before the deadline.

The contracts that allocate the most risk of delayed construction to the DWR simply relieve the Seller of any liability to provide electricity to the DWR if the natural-gas power plants do not reach commercial operation (as long as the Seller used commercially reasonable effort to achieve operation). In the State Auditor's report on the DWR contracts, the Auditor expressed concern that although the construction of new power plants was a priority for the DWR, many of the DWR's contracts lacked terms that would ensure that the new power plants would reach commercial operation (California State Auditor 2001).[63]

Table 8. Natural-Gas Power Plant Construction Deadline Penalties and Incentives in the DWR Non-Renewable Contracts

Seller	If unit does not reach operation despite Seller's reasonable effort, Seller is not liable to provide electricity	DWR can terminate with respect to any unit that does not reach operation by deadline	Seller pays DWR penalty for not reaching operation by deadline	Seller receives incentive if unit reaches commercial operation before deadline
Alliance Colton		✓		✓
Calpeak		✓	✓	
Calpine – 2	✓			
Calpine – 3	✓			
Calpine – 4	✓	✓		
Coral Power		✓	✓	
Fresno Cogeneration		✓	✓	
GWF Energy		✓		✓
High Desert		✓	✓	
PacifiCorp*				
Sempra	✓			
Sunrise		✓	✓	
Wellhead		✓	✓	

Note: Some of these contracts have been subsequently renegotiated to include different terms.
*The PacifiCorp contract says that the Seller may build a new plant, but the Seller is not required to do so under the contract.

[62] These penalties, however, are not standard among contracts: some impose a one-time penalty of about $3,000 to $6,000 per MW if a Seller misses the deadline, while others impose a penalty of about $500 per MW for each day the unit is late in reaching commercial operation.
[63] Some of the DWR's renegotiated contracts contain stronger terms to ensure that new power plants will reach commercial operation.

B. Renewable Contracts

Six of the original seven long-term renewable contracts provide for the construction of new power plants or the re-powering of existing power plants. Like all but one of the natural gas contracts that require new construction, the Seller bears the construction cost risk in all of these renewable contracts. The parties to the renewable contracts share the risk that a new power plant will not be built (or an existing plant will not be re-powered) on schedule. In particular, all of the renewable contracts allow the DWR to terminate the contract for any unit that does not reach commercial operation by a specified deadline. Interestingly, unlike a subset of the natural-gas contracts, none of the renewable contracts financially penalize the Seller if a deadline is not met.

5.2.2 Performance Risk During Operations

Not surprisingly, dispatchable natural-gas contracts have more dimensions of performance risk to manage than non-dispatchable contracts, regardless of the fuel source used to generate electricity. In the pages that follow, we therefore separate our discussion of operations-based performance risk based on dispatchability. We first describe the treatment of performance risk among the DWR's dispatchable contracts; all of these contracts rely upon natural gas. We then turn to a discussion of the non-renewable non-dispatchable contracts. Finally, we review the treatment of operations-based performance risk among the renewable contracts, all of which offer non-dispatchable energy.

A. Dispatchable Natural-Gas Contracts

Just over half of the DWR's non-renewable contracts are at least partially dispatchable; these dispatchable contracts are expected to provide over 25% of the DWR's energy over the next decade. In all of the dispatchable contracts, the DWR pays the Seller both a "capacity charge" for making the power plant available to the DWR (regardless of whether or not the DWR requests that the plant generate power), and an energy charge for the electricity that is actually delivered. All of the DWR's dispatchable contracts rely on natural gas.

There are four primary operations-based performance metrics in dispatchable natural gas-fired electricity contracts: (1) the actual generation capacity of the Seller's power plant, (2) the power plant's efficiency in generating electricity, (3) the availability of the power plant to generate electricity, and (4) the reliability with which the Seller delivers, and the DWR receives, electricity that has been dispatched by the DWR. Each of these metrics is addressed below.

The actual capacity of a dispatchable power plant is important because the DWR pays the Seller a capacity charge to have a certain amount of generating capacity available, and therefore bears the risk that the capacity of the power plant will differ from the capacity that is stated in the contract. Many of the dispatchable natural-gas contracts therefore require annual testing of the capacity of the power plant to determine the capacity charge, while other contracts simply fix the capacity charge in the contract (see Table 9, below).

Because all but one of the dispatchable contracts are tolling agreements that require the DWR to pay for the natural gas input, the DWR's fuel costs will often depend on how efficiently the power plant can produce electricity from natural gas – the plant's "heat rate." To protect against a degradation in efficiency, many of the dispatchable contracts require periodic testing or calculation of the plant's heat rate (as shown in Table 9), and the DWR's fuel payments are adjusted accordingly (i.e., the DWR is not obligated to pay higher fuel charges when plant efficiency declines). Several of the contracts that do not require heat rate testing simply calculate the fuel charge using a contractually established fixed heat rate if the Seller is providing the fuel, thereby shifting the risk that the power plant will operate inefficiently to the Seller. If, however, the DWR instead chooses to provide the fuel needed to generate the electricity – as is allowed in the tolling agreements – then these contracts shift this risk back to the DWR.

Table 9. Power Plant Performance Testing in the DWR's Dispatchable Natural-Gas Contracts

Seller	Capacity Test	Heat Rate Test
Alliance Colton	Annual Seller may re-test at any time, but no more than once a month.	Annual Seller has the right to re-test at any time, but no more than once a month.
Calpeak	At Seller's discretion or DWR's request (not more than once a year).	Annual
Calpine – 3	None	None*
Calpine – 4	Annual Each party may request two additional tests per year.	Monthly
Coral Power	None	None**
Dynegy – 2	None†	None**
Fresno Cogeneration	Annual	Monthly
GWF Energy	Annual Each party may request two additional tests per year.	Monthly
PacifiCorp	None	None**
Sunrise	Annual Seller may schedule two additional tests per year.	Biannually
Wellhead	Annual	Monthly

* The Calpine – 3 contract is a fixed-price contract (not a tolling contract), so heat rate testing would be unnecessary.
** If the Seller is providing the fuel in these contracts, the contracts' fuel charge is simply calculated using a fixed heat rate, rather than based on the actual amount of fuel consumed, making a heat rate test unnecessary. However, if the DWR provides the fuel, then the DWR bears the risk that the power plant will operate inefficiently.
† The Dynegy – 2 contract's capacity charge is based on the amount of electricity delivered rather than the capacity available, so capacity testing would be unnecessary.

Since the DWR pays the Sellers of the dispatchable natural-gas contracts to have the power plants *available* to generate power (whether or not the DWR calls upon the Seller to actually deliver power), the actual availability of the generation units is another aspect of performance uncertainty that the DWR faces. The DWR reduces its exposure to this facet of performance risk by requiring the Sellers to meet guaranteed levels of availability.

The general definition of availability in dispatchable contracts is the number of hours that the generation unit was *available* to generate power during a period, divided by the total possible number of hours the unit could have been dispatched during the period as specified in the contract (adjusted for force majeure events and scheduled outages).[64] Most of the DWR's dispatchable contracts require the Seller to meet a guaranteed level of availability, and the Seller is penalized for failing to meet the guarantee, primarily through a reduction in the capacity charge (see Table 10, below). Two contracts also provide the Seller an incentive to surpass the guaranteed level of availability. Most of these contracts guarantee availabilities of over 95% during the summer and over 90% during the rest of the year. Several contracts also set absolute minimum levels of availability below which the DWR may terminate the agreements.

Table 10. Availability Requirements in the DWR's Dispatchable Natural-Gas Contracts

Seller	Guaranteed Availability	Availability Penalties and Incentives		
		Capacity Charge Penalty	Capacity Charge Incentive	Other
Alliance Colton	June through October: 95% Annual: 95%	✓		
Calpeak	June through October, December through February: 96% All other months: 94%	✓		DWR may terminate if annual average availability is less than 60% for any two out of three years. If Seller fails to meet availability guarantee intentionally, then Seller defaults.
Calpine – 3	None			
Calpine – 4	June through October: 98% All other months: 92%	✓		
Coral Power	July through September: 97% All other months: 94.3%	✓		
Dynegy – 2*	None			
Fresno Cogeneration	June through October: 97% All other months: 94%	✓		DWR can terminate or suspend performance if the availability is less than 60% for one year.
GWF Energy	June through October: 98% All other months: 94%	✓	✓	DWR may terminate if availability is less than 60% for one year.
PacifiCorp	Annual: 88%	✓		
Sunrise	June through September: 95% Annual: 91.8%	✓	✓	
Wellhead	June through October: 97% All other months: 94%	✓		DWR can terminate if availability is less than 60% for one year.

* The Dynegy – 2 contract's capacity charge is based on the amount of electricity delivered rather than the capacity available.

[64] Some dispatchable contracts allow the unit to be dispatched in any hour of any day, whereas others restrict the possible dispatch to, for example, only peak hours.

The final major performance concern in dispatchable natural-gas contracts is the reliability with which the Seller will deliver electricity that has been *specifically scheduled* by the DWR (this is more specific than the availability guarantees, discussed above, because in this case the DWR has actually scheduled the power plant to operate on, for example, a day-ahead basis). The dispatchable contracts use "cover damages" to reduce this aspect of performance risk: if the Seller fails to deliver scheduled energy and the failure is unexcused, then the Seller pays for the DWR's incremental cost of replacement energy. What kinds of events qualify as excused outages depends on the firmness of the contract. As discussed earlier, unit-contingent contracts excuse the Seller from delivering power during generator outages and events of force majeure, while firm contracts only excuse the Seller during events of force majeure.

Eight of the DWR's eleven dispatchable contracts require the Seller to pay cover damages, however some of these contracts only require cover damages if the Seller willfully fails to deliver the scheduled energy (see Table 11, below). A few contracts further penalize the Seller (in addition to cover damages) for willfully failing to deliver scheduled energy.[65] If a contract does not require the Seller to pay the DWR cover damages for a failure to deliver energy, then the Seller is only penalized through the availability requirements discussed above.

Table 11. Remedy for Failure to Deliver Scheduled Energy in the DWR's Dispatchable Natural-Gas Contracts

Seller	Firmness	Seller pays cover damages?
Alliance Colton	Unit-Contingent	Yes, if failure is willful or due to negligence
Calpeak	Firm	No
Calpine – 3	Firm	Yes
Calpine – 4	Unit-Contingent	Yes
Coral Power	Unit-Contingent	Yes*
Dynegy – 2	Unit-Contingent	No**
Fresno Cogeneration	Firm	Yes, if failure is willful
GWF Energy	Firm	Yes, if failure is willful
PacifiCorp	Firm	No
Sunrise	Unit-Contingent	Yes
Wellhead	Firm	Yes, if failure is willful

* The Coral Power contract only requires the Seller to pay the DWR cover damages once the Seller has fallen below the availability guarantee.
** The Dynegy – 2 contract capacity charge is calculated based on the number of MWh's delivered, so the Seller is penalized for failure to deliver through a reduction in the capacity charge.

Against the backdrop of the California electricity crisis and accusations that generators were exerting market power by withholding electricity, the State Auditor expressed concern that cover

[65] The Fresno Cogeneration, GWF Energy, and Wellhead contracts require the Seller to pay a penalty equal to two times the capacity charge for any hour in which the Seller willfully fails to deliver energy. The Sunrise contract stipulates that the Seller defaults if the Seller willfully fails to deliver power to the DWR.

damages are not sufficient to protect the DWR against Sellers that repeatedly or intentionally fail to deliver power. The Auditor expressed concern that the DWR contracts do not allow the DWR to terminate a contract if a Seller repeatedly or intentionally fails to deliver power, or to inspect generation facilities to verify a generator's claims of an excused outage. The Auditor argues that cover damages cannot fully protect the DWR if a Seller is withholding electricity to exert market power in the spot market, because all of the DWR's purchases in the spot market would be at an increased price – not just the electricity the DWR purchases to replace the power withheld by the Seller (for which the Seller pays cover damages) (California State Auditor 2001).[66]

B. Non-Dispatchable, Non-Renewable Contracts

Almost half of the DWR's original non-renewable contracts are non-dispatchable; these contracts are expected to provide over 70% of the DWR's energy over the next decade. In all but one of these contracts, the Seller delivers power according to a schedule that is fixed in the contract; the only exception is the High Desert contract, in which the Seller delivers the actual electricity output of the power plant, as it is available. Since all of the non-dispatchable contracts pay the seller only when electricity is delivered (i.e., there is no capacity charge), the contracts have a built-in incentive to reduce performance risk.[67] Partly as a result, these non-dispatchable and predominantly natural gas contracts have fewer clauses designed to manage performance risk than the dispatchable natural-gas contracts.

None of the non-dispatchable contracts provide for capacity tests, and the Sellers bear the risk that the power plants will not be able to operate at the desired capacity, because the contracts require the Sellers to deliver electricity according to a fixed schedule regardless (except for the High Desert contract, as mentioned above). In addition, none of these non-dispatchable contracts provide for heat rate tests, and the Sellers therefore bear the risk that the power plants will operate inefficiently (since the Sellers are paid per MWh of electricity delivered and not based on the amount of fuel consumed).

If a Seller fails to deliver the amount of electricity established in a non-dispatchable contract, the firmness of the contract (and the circumstances surrounding the failure to deliver) will determine if the Seller is excused from delivery (see Table 12, below). If the Seller is not excused from delivering power and fails to deliver (or if the DWR fails to receive) scheduled energy, the party at fault is required to pay the other party cover damages.

The only other performance penalty contained in the DWR's non-dispatchable, non-renewable contracts is an availability guarantee, contained in only two contracts. In the non-dispatchable contracts, the definition of availability is the percent of the scheduled energy that is actually delivered by the Seller, which differs from the definition of availability in the dispatchable contracts. The Allegheny contract requires the Seller to deliver at least 90% of the scheduled energy (or else the DWR could declare the Seller in default of the contract), while the Williams

[66] Some of the DWR's renegotiated contracts contain stronger terms to address the Auditor's concerns regarding Sellers that repeatedly or intentionally fail to deliver power.
[67] The Sempra contract is the only non-dispatchable contract that is also a tolling agreement. Although the DWR pays for the cost of gas in the Sempra contract, there is no capacity charge and the pricing structure is designed such that the DWR only pays Sempra when electricity is delivered.

contract requires the Seller to deliver at least 70% of the scheduled energy and provides performance penalties and incentives based on the availability requirement.

Table 12. Firmness of the DWR's Non-Dispatchable, Non-Renewable Contracts

Seller	Firmness
Allegheny	Unit-Contingent
Calpine – 1	Firm
Calpine – 2	Unit-Contingent
Dynegy – 1	Firm
El Paso	Firm
High Desert	Unit-Contingent
Morgan Stanley	Firm
Sempra	Firm
Williams	Unit-Contingent

C. Renewable Contracts

All of the DWR's renewable contracts are fixed-price and are non-dispatchable. A primary mechanism the renewable contracts use to manage performance risk is built-in to the structure of the pricing terms: the Seller is only paid for electricity that is delivered. There is some variation in how the renewable contracts further manage performance risk, and we consider each of these variations in turn.

Out of all the renewable contracts, the DWR bears the most performance risk in the two wind contracts. The wind contracts deliver electricity as-available, and have no availability requirement. If the wind plants do not deliver as much energy as they might be capable of delivering, the Sellers are not penalized. However, the wind contracts do require the Sellers to pay cover damages if they fail to deliver *scheduled* energy and the failure is unexcused (changes in wind resource conditions would be an excused outage).

At the time the DWR contracts were signed, the California ISO heavily penalized electricity suppliers who delivered less electricity than they had scheduled with the ISO (through "imbalance charges"). This rule was intended to prevent gaming of the market; however, it represented a uniquely large financial risk for wind power generators, since future wind supply cannot be predicted with extreme accuracy. In both of the DWR's wind contracts, the DWR agreed to accept this aspect of performance risk, and to pay any ISO imbalance charges that might arise. The ISO subsequently revised its rules to facilitate the use of intermittent energy sources, which will reduce the DWR's potential cost exposure (FERC 2002a).

The landfill gas and two of the three biomass contracts require the Sellers to deliver energy at the plants' maximum capability in every hour, instead of requiring the Sellers to deliver energy according to a schedule set in the contract (as most of the non-renewable, non-dispatchable contracts require). None of these renewable contracts require capacity tests, thereby shifting this aspect of performance risk to the DWR. However, the Sellers bear the risk that their power plants will operate inefficiently, since they are only paid based on how much electricity is delivered.

If the Seller in either the landfill gas or the two biomass contracts discussed above fails to deliver power that is specifically *scheduled* (and they are not excused from delivery based on the contracts' firmness provisions), they are not required to pay the DWR cover damages. However, the Sellers are obliged to meet two other requirements designed to reduce the amount of performance risk the DWR bears. First, the Sellers are required to deliver within plus or minus 10% of the monthly schedules that they submit to the DWR (or else default on the contract and pay a sizeable termination payment).[68] Second, the Sellers are required to deliver over 70% to 75% of the total potential electricity that could be generated by the unit, based on the plant's capacity given in the contract; if a Seller fails to meet this availability guarantee for three consecutive months, the DWR can terminate the contract (see Table 13, below).

The geothermal contract is very similar to the landfill gas and two biomass contracts discussed above, except the geothermal contract has no availability requirement, and instead the Seller is required to pay the DWR cover damages for failing to deliver energy that is specifically scheduled.

The Imperial Valley biomass contract is nearly identical to a non-dispatchable, non-renewable contract in how it manages performance risk. The specific energy delivery schedule is set in the contract, and the Seller has no availability requirement and instead pays cover damages for failing to deliver scheduled energy.

[68] The termination payment is equal to the difference between the present value of the existing contract and a replacement contract.

Table 13. Key Contract Terms that Allocate Performance Risk in the DWR Renewable Electricity Contracts

Seller	Renewable Resource	Firmness	Contract clauses relevant to performance risk	Availability Requirement and Penalties	Seller pays cover damages?	DWR pays cover damages?
Capitol Power	Biomass	Unit-Contingent	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 105% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	▪ June through October: 75%; Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate.	No	Yes
Clearwood	Geothermal	Unit-Contingent	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 120% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	▪ None	Yes	Yes
County of Santa Cruz	Landfill gas	Unit-Contingent	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours, not to exceed 105% of contract capacity. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	▪ June through October: 75%; Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate.	No	Yes
Imperial Valley	Biomass	Firm	▪ DWR must take (Seller must deliver) quantity of energy set in contract.	▪ None	Yes	Yes
PG&E Energy Trading	Wind	As-available	▪ Electricity is generated when sufficient wind is available.	▪ None	Yes	Yes
Soledad	Biomass	Unit-Contingent	▪ DWR must take (Seller must deliver) plant's maximum capability in all hours. ▪ Seller must operate the plant such that monthly actual generation is within plus or minus 10% of monthly scheduled generation.	▪ June through October: 75%; Otherwise: 70% ▪ If plant doesn't meet availability guarantee for 3 consecutive months, DWR can terminate.	No	Yes
Whitewater	Wind	As-available	▪ Electricity is generated when sufficient wind is available.	▪ If no energy is generated and delivered for a period of six months for reasons other than weather related conditions, DWR may terminate.	Yes	Yes

Note: Some of these contracts have been renegotiated.

5.3 Summary of Performance Risk

Parties to an electricity contract are able to better control and manage (as opposed to just allocate) performance risk than any other risk discussed in this paper. Ideally, contracts should allocate risks to those parties best able to manage the risks. Clearly, the Seller is best able to control the performance of its power plant(s). Contracts therefore allocate a substantial amount of performance risk to the Sellers, and provide incentives for the Sellers to perform in a way that reduces the uncertainties faced by the buyer. This section shows that there are considerable differences in the treatment of performance risk between the DWR's dispatchable and non-dispatchable contracts, regardless of the fuel source.

Some renewable sources impose an additional source of risk on the DWR. To the extent that renewable generation is based on a variable underlying fuel stream (for example, wind), some renewable contracts clearly cannot have the same electricity delivery and dispatchability provisions as can contracts for natural gas generation. Issues of dispatchability and predictability are discussed in more detail in the next section of this report on Demand Risk. While some sources of renewable energy are therefore held to different and lower delivery standards than are natural gas plants, we find that the treatment of performance risk in the renewable contracts is largely similar (though a bit more lenient) to the treatment of those same risks in the DWR's non-dispatatchable contracts for conventional energy.

One of the differences between the performance risk clauses in the renewable and natural-gas contracts is that the renewable contracts do not penalize the Seller if a power plant is delayed in reaching commercial operation (other than allowing the DWR to terminate the contract), whereas several of the natural gas contracts contain penalties in addition to the DWR's termination rights. The DWR also assumed additional performance risk in the two wind contracts by agreeing to bear any ISO imbalance charges that might arise, an aspect of performance risk that is not a significant concern in the other DWR contracts. The use of cover charges and availability guarantees also differ somewhat between the renewable and non-renewable contracts.

6 Demand Risk in Electricity Contracts

The amount of electricity that a utility is responsible for supplying to its customers varies on very short time scales (minute-to-minute) and on longer time scales (year-to-year). Electricity demand is impacted by population growth, the state of the economy, the time of day, and weather and temperature, among other factors. The variability of electricity demand can make predicting electricity demand, and contracting to satisfy that demand, a difficult task.
Since electricity demand is variable and uncertain, instantaneously supplying enough electricity to meet demand requires significant coordination among power plants operations. Certain power plants are better able to respond to changes in electricity demand, thus mitigating demand risk. This section addresses the treatment of demand risk in the DWR's contracts, specifically comparing the renewable and natural gas contracts based on their deliverability and dispatchability characteristics.

6.1 Demand Risk Fundamentals

Electricity is a unique commodity because it cannot be economically stored (to any significant extent) and it must therefore be simultaneously produced by the supplier and utilized by the customer. Since electricity demand is variable and uncertain, the parties to an electricity contract face "demand risk": the risk that the electricity that has been contracted for will not be needed as anticipated, or that there will not be enough electricity to meet fluctuating demand.

In order to reliably provide customers with electricity and to reduce demand risk, the owner of a portfolio of electricity supplies must design the portfolio to be able to supply electricity to follow the customers' load; this requires the use of dispatchable resources or contracts.[69] A dispatchable contract allows the party purchasing the power to tell the Seller when and how much electricity to generate (within limits).[70]

Non-dispatchable contracts, in contrast, generally deliver "blocks" of power (fixed amounts of electricity) during hours that are set in the contract (for example, baseload or peak hours), or in the case of renewable energy, provide as-available output. Non-dispatchable power is more valuable if it is delivered during peak periods and if it is for firm delivery; in these cases, the Buyer is assured of receiving power when it is otherwise most costly to purchase in the spot market. Renewable generation technologies, in general, are more difficult to dispatch than natural gas-fired electricity generation technologies. Some forms of renewable electricity may also deliver more power during off-peak periods than other forms of generation, and may not be willing or able to offer fixed blocks of delivered electricity (preferring, instead, as-available delivery that can, all else equal, exacerbate demand risk somewhat).

[69] Renewable generation facilities may also be able to reduce demand risk by providing increased flexibility due to short construction lead-times and the modular nature of certain technologies (Hoff 1997); certain natural gas-fired generation facilities (e.g. peakers) also have these characteristics.
[70] Electricity providers can also use dispatchable demand contracts (i.e., contracts with customers that agree to decrease demand upon request) in place of dispatchable supply contracts to maintain the necessary supply-demand balance.

Because of demand risk, dispatchable contracts are, all else equal, of more value than non-dispatchable contracts. It deserves note, however, that utilities or other load serving entities only need enough dispatchable power to "top-off" the electricity provided by non-dispatchable plants (i.e. only a portion of the load varies) A least-cost electricity supply portfolio will therefore typically still contain a substantial amount of non-dispatchable electricity generation.

Since generators are generally not required to deliver electricity when their power plants are undergoing routine maintenance, the timing of maintenance can also introduce uncertainty into an otherwise relatively certain electricity delivery (or potential dispatch) schedule. In order to reduce this uncertainty, and to ensure that electricity is delivered when it is most needed, electricity contracts often constrain when the Seller can perform maintenance.

6.2 Demand Risk in the DWR Contract Sample

About one-quarter of the total energy the DWR had under its original contracts for the next decade was dispatchable. All of these dispatchable contracts are for electricity from natural gas fueled power plants (see Table 14, below).

Since almost three-quarters of the DWR's energy was non-dispatchable, the DWR contracts arguably do not do enough to combat demand risk. In particular, the State Auditor's analysis of the DWR contracts found that the DWR's overall portfolio of electricity contracts includes excess deliveries of baseload energy and insufficient deliveries of (or insufficient dispatchable deliveries of) peak electricity (Auditor 2001, pg. 23). Evidence of the amount of demand risk that the DWR bears has materialized, as the DWR has been forced to sell "must-take" (non-dispatchable) power at a loss (Marcus 2002).[71]

The renewable energy contracts signed by the DWR are all non-dispatchable, representing a lower value product than a dispatchable source (all else being equal). With some exceptions, the renewable contracts also offer more variable and uncertain output profiles than the non-dispatchable contracts for conventional energy supplies. These renewable contracts, however, represent a small fraction (less than 2%) of the non-dispatchable energy under contract. Therefore, despite the fact that some renewable sources do less to reduce the DWR's demand risk than do conventional energy supplies, it is the non-dispatchable natural gas contracts that are the principal concern among the DWR contract sample.

For the purpose of analyzing the ability of the DWR contracts to mitigate demand risk, the DWR's non-renewable electricity contracts can be divided into three groups: (1) non-dispatchable, (2) dispatchable, and (3) partially dispatchable. We consider each of these groups in more detail below, followed with a specific discussion of the renewable energy contracts.

[71] A number of the recently renegotiated contracts decrease the DWR's demand risk by increasing the DWR's dispatch flexibility in contracts that were previously non-dispatchable.

Table 14. Dispatchability of the DWR Long-term Contracts

Seller	Dispatchable?	Resource	Ten-year Energy Purchases (GWh)‡
Allegheny	No	Natural gas	63,898
Calpine – 1	No	Unspecified	64,596
Calpine – 2	No	Natural gas	70,115
Dynegy – 1	No	Natural gas	14,246
El Paso	No	Unspecified	2,441
High Desert	No	Natural gas	51,896
Morgan Stanley	No	Unspecified	2,136
Sempra	No	Natural gas	93,325
Williams	No	Natural gas	56,535
	Total Non-Dispatchable, Non-Renewable Contracts		**419,189 (72%)**
Alliance Colton	Partially	Natural gas	1,468
Calpeak	Yes	Natural gas	5,027
Calpine – 3	Yes	Natural gas	8,001
Calpine – 4	Yes	Natural gas	3,024
Coral Power	Partially	Natural gas	28,677
Dynegy – 2	Partially	Natural gas	21,174
Fresno Cogeneration	Yes	Natural gas	950
GWF Energy	Yes	Natural gas	23,713
PacifiCorp	Yes > 2002	Natural gas	21,900
Sunrise	Yes	Natural gas	38,888
Wellhead	Yes	Natural gas	4,047
	Total Dispatchable, Natural Gas Contracts		**156,870 (27%)**
Capitol Power	No	Biomass	590
Clearwood	No	Geothermal	1,692
County of Santa Cruz	No	Landfill Gas	112
Imperial Valley	No	Biomass	362
PG&E Energy Trading	No	Wind	2,017
Soledad	No	Biomass	410
Whitewater	No	Wind	3,263
		Total Renewable Contracts	**8,448 (<2%)**
		TOTAL	**584,506 (100%)**

Note: Only DWR contracts with terms of three years and longer are included in this table. Also note that a number of these contracts have subsequently been renegotiated with altered terms and, on average, increased dispatchability.

‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001).

A. Non-Dispatchable, Non-Renewable Contracts

All but two of the original non-dispatchable, non-renewable contracts specify how much electricity the Seller will deliver and when (the delivery schedule). Since the DWR cannot choose when to have electricity delivered in these contracts (after a contract is finalized), and the

DWR must pay the Seller for every MWh of electricity that is delivered (whether or not the DWR needs the electricity), these contracts do not directly and completely mitigate DWR's demand risk.[72] Because some of the contracts require delivery during peak periods, however, they do mitigate DWR's demand risk somewhat.

Those contracts that offer unit-contingent electricity supply are relatively more risky than those that offer firm delivery, as the DWR has less assurance of delivery on any particular hour or day with unit-contingent contracts. Many of the considerations raised in Section 5 regarding incentives and penalties for performance therefore have a direct bearing on the amount of demand risk faced by DWR (the reader is referred to Section 5 on these issues, as they are not repeated here).

The Williams contract does less to mitigate the DWR's demand risk than do the other non-dispatchable contracts because the Williams contract allows the Seller to provide the DWR with a significant amount of must-take energy each month, at the *Seller's* option. The High Desert contract's delivery schedule is also somewhat more uncertain because the Seller is required to deliver the actual output of its power plant to the DWR in all hours, without specification of exactly when and how much electricity will be provided.

To somewhat decrease the amount of demand risk born by the DWR, half of the non-dispatchable contracts restrict the timing of when the Seller can do routine maintenance (excluding the contracts that provide electricity from unspecified "market" sources, which do not need to include maintenance restrictions because they offer continuous delivery of electricity).

Table 15. Maintenance Restrictions in the DWR Non-Dispatchable, Non-Renewable Contracts

Seller	Resource	Maintenance Restrictions
Allegheny	Natural gas	None
Calpine – 1	Unspecified	N/A*
Calpine – 2	Natural gas	None
Dynegy – 1	Natural gas	Seller will avoid peak hours
El Paso	Unspecified	N/A*
High Desert	Natural gas	Seller will avoid July, August and September, and schedule maintenance with DWR
Morgan Stanley	Unspecified	N/A*
Sempra	Natural gas	None
Williams	Natural gas	Scheduled maintenance will occur November through April, and will not exceed 14 days per unit per year.

* The contracts that provide electricity from unspecified "market" sources offer firm delivery from a diversified portfolio of power suppliers, and therefore do not require maintenance restrictions per se.

[72] These non-dispatchable contracts are also known as "take-or-pay" or "must-take" contracts.

B. Dispatchable Natural-Gas Contracts

In contrast to the non-dispatchable contracts, the DWR's original dispatchable natural-gas contracts do not require the DWR to take a specified quantity of energy. Rather, the dispatchable contracts define the parameters within which the DWR can request that the Seller deliver power. In all of the dispatchable contracts, the DWR pays the Seller both a capacity charge for making the power plant available to the DWR, and an energy charge for the electricity that is actually delivered. Dispatchable contracts can help the DWR mitigate its demand risk by allowing the DWR to schedule electricity to match its changing load.

The DWR's dispatchable contracts allow the DWR to dispatch the specified power plants either the day before the electricity is needed, on a real-time basis, or both (see Table 16, below). The contracts contain numerous constraints on how the DWR is allowed to dispatch the power plants, however, in large part to ensure that the power plants are run within their technical operating limits and are not unduly stressed. (Many contracts supply power from multiple power plants, but the dispatch constraints are usually with regard to each individual power plant or generating "unit.")

The primary constraints on the DWR's dispatch flexibility are:

- the maximum number of times the generating unit(s) can be started each day (commonly two times per day),
- the minimum number of consecutive hours that a dispatched unit must run (commonly four hours), and
- the smallest increment of capacity that can be dispatched if the DWR wants the Seller to deliver any power (ranges from 21 MW to 195 MW).

Some contracts also explicitly state that the DWR's dispatch must be within the operating specifications of the units (e.g., the unit's ramp rate), though this is presumably required implicitly for any unit.

To further reduce the amount of demand risk that the DWR bears, most of the DWR's dispatchable contracts also restrict the timing of when the Seller can do routine maintenance, as shown in Table 16. In general, the contracts require that the Sellers avoid performing maintenance during the summer months and during peak hours, when it may be the most difficult for the DWR to procure replacement energy.

As mentioned previously in Section 4, it is interesting to note that all but one of the DWR's dispatchable contracts are also tolling agreements.[73] Since a generator with a dispatchable contract does not know in advance when it will generate electricity, it would be challenging for the generator to reduce its fuel price risk using physical or financial fuel supply contracts; hence, dispatchable contracts are frequently tolling or indexed-price agreements which allocate the fuel price risk to the purchaser of the electricity. Finally, it deserves reiteration that the penalties and

[73] The Calpine – 3 contract is the only fixed-price dispatchable contract.

incentives provided for plant performance also play a strong role in reducing or enhancing demand risk for the Buyer (see Section 5).

Table 16. Dispatch Flexibility and Maintenance Restrictions in the DWR's Dispatchable Natural-Gas Contracts

	Timeframe of Allowed Dispatch		Dispatch Constraints			Maintenance Restrictions
Seller	**Day-Ahead**	**Real-time**	**Maximum number of start-ups per day**	**Number of consecutive hours unit must run if dispatched**	**Smallest increment of capacity that can be dispatched***	
Calpeak	✓	✓	2	4	Unspecified	Seller will schedule maintenance during November, March, April and May.
Calpine – 3	✓	✓	Unspecified	4	36 MW (>80% of unit)	None
Calpine – 4	✓	✓	Unspecified	4	36 MW (>80% of each unit)	None
Fresno Cogeneration	✓		2	4†	21.3 MW (100% of unit)	Seller will avoid summer months and peak hours
GWF Energy	✓	✓	1	Unspecified	44 MW (100% of each unit)	Seller will avoid peak hours, and provide DWR notice
PacifiCorp**		✓	Unspecified	Unspecified	25 MW	Seller provides DWR 30 days non-binding advance notice of scheduled maintenance
Sunrise		✓	Unspecified	2 to 6	195 MW (>60% of full output)	Seller will avoid June through September
Wellhead		✓	2	4†	42 MW (100% of each unit)	Seller will avoid summer months and peak hours

*Some contracts have more than one unit with different capacities.
**The PacifiCorp contract is dispatchable after 2002
† With three hours of non-operation between dispatches.

C. Partially Dispatchable Natural-Gas Contracts

The DWR's three partially dispatchable natural-gas contracts lie somewhere in between the dispatchable and non-dispatchable contracts in the amount of flexibility the contracts provide the DWR to decide when electricity will be delivered. All of the partially dispatchable contracts require the DWR to purchase a minimum quantity of electricity, and allow the DWR to dispatch an additional quantity of energy. Of these contracts, the Coral Power contract provides the DWR with the least amount of flexibility, and is unusual because it provides the Seller with flexibility to change the amount of power actually delivered (see Table 17, below). The partially dispatchable contracts also have similar maintenance restrictions to the dispatchable contracts.

Table 17. Dispatch Flexibility and Maintenance Restrictions in the DWR's Partially Dispatchable Natural-Gas Contracts

	Timeframe of Allowed Dispatch		Dispatch Constraints				Maintenance Restrictions
Seller	**Day-Ahead**	**Real-time**	**Maximum number of start-ups per day**	**Number of consecutive hours unit must run if dispatched**	**Smallest increment of MW that can be dispatched**	**Other constraints**	
Alliance Colton	✓	✓	2	8	10 MW (100% of each unit)	DWR must choose number of dispatchable hours (for most of the dispatchable energy) annually. Once chosen, these hours are take-or-pay.	Seller will avoid June through October and peak hours.
Coral Power	✓		Unspecified	10	25 MW	Most energy is non-dispatchable. Seller has option to cancel about half the energy by 2003, and to pay DWR a penalty. Beginning in 2006, DWR may reduce baseload deliveries, in increments of 25 MW, however DWR must still pay Seller $25.16 per MWh not delivered. Prior to each year, Seller may inc. or dec. the delivered quantities for the coming year by 10% (except that baseload deliveries may not be increased).	None
Dynegy – 2	✓		Unspecified	Unspecified	50 MW	Two-thirds of the capacity during peak hours is non-dispatchable.	Seller will avoid peak hours, and provide DWR notice.

D. *Renewable Contracts*

All of the DWR's renewable contracts are non-dispatchable, and therefore do little to mitigate the DWR's demand risk. The Imperial Valley biomass contract is similar to many of the non-dispatchable natural-gas contracts: electricity is to be supplied according to a schedule fixed in the contract. The DWR has slightly less certainty in energy delivery in the landfill gas, geothermal, and the other biomass contracts, because all of these contracts require the Seller to supply electricity at the power plants' "maximum capability" (with some restrictions).[74] Though this is similar to the High Desert natural-gas contract, some of the renewable plants arguably may have more uncertain fuel supplies than the natural gas plant, increasing the DWR's demand risk relative to the High Desert contract (this is certainly true for "normal" supply fluctuations, but as addressed in an earlier section, natural gas plants may be subject to greater risks of systematic and catastrophic fuel supply interruptions). The DWR's two wind power contracts provide the least certainty to the DWR because they are to supply electricity on an as-available basis, and because the electricity deliveries are neither dispatchable nor predictable significantly in advance of delivery.

As with the natural-gas contracts, almost all of the renewable contracts restrict the timing of routine maintenance to reduce the amount of demand risk born by the DWR (see Table 18, below). In general, the renewable contracts require the Sellers to avoid performing maintenance during peak months, and require the Sellers to provide advance notice of maintenance schedules to the DWR. Four of the seven renewable contracts also limit the number of days each year the Seller can have outages to perform maintenance.

Table 18. Maintenance Restrictions in the DWR's Renewable Contracts

Seller	Maintenance Restrictions
Capitol Power	Seller will avoid June through October, and provide DWR 30 days notice. Maintenance outages allowed for 40 days per year.
Clearwood	Seller will avoid peak months, coordinate schedule with DWR, and provide DWR with list of scheduled maintenance periods each year.
County of Santa Cruz	Seller will avoid June through October, and provide DWR 30 days notice. Maintenance outages allowed for 20 days per year.
Imperial Valley	Seller will avoid peak hours, and provide DWR with 14 days notice. Four maintenance outages, lasting an aggregate of 15 days, per year.
PG&E Energy Trading	None
Soledad	Seller will avoid June through October, and provide DWR 30 days notice. Maintenance outages allowed for 20 days per year.
Whitewater	Seller will schedule maintenance during November, March, April and May.

[74] The Capitol Power, Clearwood, County of Santa Cruz, and Soledad contracts require the Sellers to deliver within plus or minus 10% of the monthly schedules that they submit to the DWR. In addition, if the Seller makes a same-day change in its schedule that results in an increase to its output, the DWR has the right, but not the obligation, to purchase the increase at the contract price.

6.3 Summary of Demand Risk

The DWR mitigated its exposure to demand risk primarily by purchasing about one quarter of its total electricity through dispatchable natural-gas contracts. The DWR further reduced its risk by (1) tailoring the delivery pattern of its non-dispatchable natural-gas contracts to the DWR's expected load requirements (i.e., requiring delivery during peak periods for some of the non-dispatchable contracts), and (2) imposing power plant maintenance restrictions.

While the dispatchable contracts reduce the DWR's demand risk, they also increase the DWR's exposure to fuel price risk because almost all of the dispatchable contracts are natural gas tolling agreements. This highlights a fundamental tradeoff between demand and fuel price risks.

In part because of this tradeoff, it is not necessary or valuable to have all contracts in an electricity portfolio be dispatchable; instead, it is only valuable to have dispatchable contracts provide electricity for the variable part of the load. As noted earlier, however, the State Auditor's report on the DWR contracts found that the DWR did not take full and sufficient advantage of the dispatchability that natural gas-fired electricity contracts can provide, and partly as a consequence, the DWR has already been forced to sell large quantities of non-dispatchable power at a loss. The DWR has renegotiated several contracts, however, and increased the dispatch flexibility in contracts that were previously non-dispatchable.

Unlike some natural gas technologies, renewable energy projects are rarely dispatchable. None of the DWR's renewable contracts are dispatchable, and most of the contracts offer less demand risk mitigation potential than even the non-renewable, non-dispatchable contracts. This is because, with one exception, the renewable contracts do not offer fixed energy-delivery schedules that are established well in advance of delivery. Wind contracts, in particular, are not well suited to mitigating demand risk.

Despite this feature of renewable contracts, the DWR's renewable contracts do not, in aggregate, impose a substantial burden on the DWR or the state. In part, this is because the total amount of electricity to be delivered under these contracts is less than 2% of the DWR's overall portfolio. Moreover, demand risk can readily be managed through dispatchable natural gas contracts and non-dispatchable contracts with tailored delivery patterns. Accordingly, a certain amount of renewable energy can be integrated into electricity systems with effectively no or limited incremental cost (it is beyond the scope of this paper to calculate that cost or evaluate at what point the integration of non-dispatchable or intermittent electricity supplies becomes costly). To the extent that the DWR's contracts do not sufficiently mitigate demand risk, that problem is predominantly the result of the DWR's sizable number of non-disptchable natural-gas contracts.

7 Environmental Risk in Electricity Contracts

The laws and regulations governing the environmental impacts of electricity generation are likely to change within the term of many of the DWR's contracts, as will the cost of compliance with existing environmental regulations. In this section, we examine how the DWR contracts manage the risk related to compliance with existing environmental requirements, and the risk that future environmental regulations will affect the cost or legal ability to generate electricity.

We use the phrase "environmental risk" to mean the financial risk to which parties to an electricity contract are exposed stemming from environmental regulations. For example, the possibility of a future carbon tax is an environmental risk (in our definition) from the perspective of the parties to an electricity contract. Environmental risk is therefore a subset of broader regulatory risks; we discuss other specific regulatory risks in Section 8.

As will be shown below, environmental compliance risks are heavily dependent on the fuel source and technologies used to generate electricity. How environmental compliance costs impact electricity customers depends on the allocation of this risk between the Buyer and the Seller to a contract. As a general matter, the DWR's renewable contracts are less likely to be impacted by these risks than are the natural gas-fired contracts.

7.1 Environmental Risk Fundamentals

Parties to an electricity contract face a significant amount of uncertainty due to (1) the application of current environmental regulations, and (2) the possibility of future changes in environmental regulations. These environmental compliance risks can impose potentially large costs on the parties to an electricity contract. Some possible future environmental regulations include a carbon tax (or other form of carbon regulation), a renewables portfolio standard, and further regulation of sulfur dioxide, nitrogen oxides, fine particulates, and mercury emissions (EIA 2001a).

The allocation of environmental risks in the electricity industry can also play an important role in determining what types of power plants get built, and thereby the overall environmental performance of the electricity system. For example, if the U.S. Congress had not passed the Price-Anderson Act – which allocates most of the risk of a nuclear power plant catastrophe to the public – it is less likely that a private company would have been willing to build a nuclear power plant (Cohn 1997).

In an electricity contract, a party's exposure to environmental risk depends on three factors:

- the technological characteristics and environmental impacts of the power plant(s),
- the allocation of environmental compliance risks in the electricity contract, and
- in the case of a new environmental regulation, the details of how the regulation is implemented.

Power plants fueled by conventional fossil fuels are generally believed to damage the environment more than renewable generation facilities. Hence, parties to a contract for electricity generated from fossil fuels are more exposed to environmental risks than parties to a contract for renewable electricity. Contracts may contain requirements for environmental performance and equipment upgrades to mitigate environmental risk exposure. However, the type of power plant that is built (and the emissions controls required on that power plant) is the primary determinant of the parties' aggregate environmental risk exposure.

Though aggregate environmental risk exposure is determined in part by the type of power plants used to generate electricity, the incidence of those risks on the Buyer or the Seller depends on their specific allocation in electricity contracts. Electricity contracts can allocate environmental compliance risks to either the Buyer or the Seller, or the contract can split the risk between the parties. Since there are numerous sources of environmental risk, it is very unlikely that a contract could allocate *all* environmental risk to one party or the other; rather, the allocation of environmental risk is typically multi-dimensional, with different environmental risks allocated between the parties in different ways.

As already noted, environmental compliance risk can arise from both existing environmental regulations and from the possibility of future environmental regulations. When the risk is due to a possible future regulation, the amount of risk a party is exposed to is determined in part by the details of how the new regulation is implemented. For example, if a future carbon tax were levied on the use of natural gas, by default the Seller would bear the cost of the carbon tax in most contracts. If the carbon tax were instead levied on the use of electricity, however, the Buyer would bear the cost. Because of this, contract clauses not specifically intended to allocate environmental compliance risk might nevertheless play a role depending on how a new regulation is implemented. For example, if a future carbon tax were levied on the use of natural gas, the Seller would bear the cost of the tax in a fixed-price natural gas-fired electricity contract; in a tolling contract, however, the Buyer might bear the cost of the tax. Of course, new environmental regulations might also "grandfather" existing power plants and excuse them from being subject to the new regulation altogether.

When a party to an electricity contract accepts an environmental compliance risk, it implies something about that party's conception of the severity of the risk and the likelihood that a regulation will be implemented (as well as the party's risk aversion). The common practice of grandfathering new environmental regulations undoubtedly influences these perceptions. Nonetheless, when deciding what electricity contracts to sign, an electricity purchaser must account for the possible future costs of environmental compliance to which the purchaser would be exposed. Likewise, when sellers of electricity are exposed to environmental compliance risks, they will presumably increase the contract price to account for the cost of bearing the risks.

7.2 Environmental Risk in the DWR Contract Sample

The DWR contracts mostly allocate the risk of compliance with *current environmental regulations* (e.g., pollution permits) to the Seller, either explicitly or by default. If the cost of meeting these regulations increase, it is the Seller that bears most of these costs. There are some notable exceptions, however, and three contracts with conventional power plants allocate the risk (and cost) of acquiring pollution permits to the DWR, resulting in a potential cost exposure for the DWR on the order of a billion dollars, as discussed in further detail below.

Only thirty-five percent of the DWR's original non-renewable contracts (representing 45% of the DWR's non-renewable energy under contract) allocate the risk of *future environmental regulations* in a comprehensive manner.[75] All of these contracts allocate the risk of future environmental regulations predominantly to the DWR. The fact that relatively few of the DWR's contracts allocate this risk comprehensively may be attributed to either a lack of concern about the cost of future environmental regulations or a lack of awareness of their potential cost.

Despite the lack of comprehensive treatment, if future environmental regulations are enacted that apply to the power plants under contract to the DWR, the DWR and thus electricity customers could be exposed to sizeable costs; new regulations may also result in costly legal battles for the DWR for the contracts that do not explicitly allocate environmental risk. The possibility of future carbon regulation is perhaps the greatest risk. For example, as illustrated below, if carbon regulation leads to costs in the range of $10 or $100 per metric ton of carbon equivalent, the DWR could face additional costs through 2010 that range from as low as $12 million to as high as $8.5 billion (0.005 cents per kWh to 1.5 cents per kWh) depending in part upon the date of implementation.

Renewable energy contracts generally reduce aggregate exposure to environmental risk because renewable electricity sources are generally less environmentally damaging than non-renewable technologies. The purchaser of renewable electricity may not benefit from the environmental risk mitigation that the contract can provide, however, unless the benefit is allocated to the purchaser in the contract. For example, both of the DWR's wind power contracts allow the Seller to retain the rights to the renewable attributes of their wind power facilities(i.e., the renewable energy credits, or RECs). Consequently, as discussed in further detail below, although the DWR is nominally purchasing 1.5% of its electricity from renewable resources under long-term contract, from the perspective of mitigating environmental risk the DWR is only purchasing both electricity and renewable attributes for about 0.5% of its total electricity purchases. With California's recently signed renewables portfolio standard (RPS), DWR's decision to give up the rights to the renewable energy credits could expose the state to approximately $40 -$80 million in additional costs.

7.2.1 Risk of Compliance with Current Environmental Regulations

The construction and operation of power plants is heavily regulated, in large part because power plants have a significant impact on the environment. The risk that a power plant owner faces due to *existing environmental regulations* can be divided into two categories: pre-operation and post-operation. Prior to reaching commercial operation, a power plant usually must go through an extensive siting process and acquire a number of environmental permits. This process can be quite lengthy, and power plants sometimes encounter intense public opposition. Once a power plant reaches commercial operation, the plant must maintain permits (particularly air pollution permits) in order to operate. Pollution permit prices can be volatile, and power plants can run

[75] The Calpine – 1, Calpine – 2, Calpine – 3, Dynegy – 1, Dynegy – 2, GWF Energy, and Williams contracts allocate the risk of a new environmental regulation passed by any governmental authority. All other contracts only allocate the risk of regulations passed by either the federal or state government, or regulations that are targeted at energy services.

out of the permits they need to continue operating; both of these factors were blamed in part for the extremely high electricity prices during California's crisis.

A. Non-Renewable Contracts

In all of the DWR's original natural gas-fired electricity contracts that provide for the construction of new generating facilities, both parties share the risk that a unit will not reach commercial operation. In order to reach commercial operation, a power plant must pass an environmental review and permitting process. If a unit does not reach commercial operation by a deadline, most of the DWR's contracts simply allow the DWR to terminate the portion of the contract pertaining to the unit, and some contracts require the Seller to pay a penalty. (This is discussed in Section 5 on Performance Risk.) Three of the DWR's natural-gas contracts specifically address the risk that the failure to reach commercial operation is due to the Seller's inability to acquire the necessary environmental permits. The Alliance Colton, Coral Power, and High Desert contracts allow the Seller to terminate the relevant portion of the contract, with no further liability, if they are unable to obtain the necessary permits.

Once a power plant has been built, the plant must remain in compliance with existing environmental regulations and, sometimes, acquire air pollution allowances on an ongoing basis in order to operate. Half of the DWR's non-renewable contracts specifically assign responsibility for acquiring or paying for the permits necessary to produce electricity; most of these contracts allocate the responsibility of acquiring permits to the Seller (see Table 19, below). By default, in the remaining contracts that do not explicitly allocate this risk, the responsibility is presumed to rest with the Seller. Accordingly, if the cost of meeting existing environmental regulations increases, these costs are typically born by the Seller, not the DWR.[76]

Three of the DWR's original contracts, however, require the DWR to pay for the operational environmental permits required to generate electricity. The Williams contract requires the DWR to pay for the cost of emission credits, while the two Dynegy contracts require the DWR to pay for both the cost of the permits and for the cost of exceeding the power plants' applicable emission limits (to the extent necessary to supply the electricity under contract). The State Auditor's report presents an analysis of these unusual contract clauses, and estimates that the Williams contract alone could expose the DWR to between \$400 million and \$688 million in additional costs over the lifetime of the contract, or between 0.7 and 1.2 cents per kWh (California State Auditor 2001).[77] Similarly, the Dynegy contracts could expose the DWR to additional costs on the order of \$300 million for the emission credits alone, not including the cost of exceeding the power plants' emission limits.

[76] Two of the non-renewable contracts that allocate the responsibility of acquiring permits to the Seller also contain clauses that address the Seller's performance at acquiring the permits: the Sunrise contract rewards the Seller for obtaining permits beyond those required to generate the maximum amount of energy in the contract, while the Alliance Colton contract does not penalize the Seller if the Seller is unable to obtain some of the permits necessary to deliver the amount of energy specified in the contract (instead, the contract simply reduces the energy deliveries).
[77] These contract clauses were chosen by the California State Auditor as among the most "troubling" contract provisions in the DWR's contracts (California State Auditor 2001). The Auditor assumes that emission credit prices will remain capped at \$15,000 per ton.

Table 19. Explicit Allocation of the Risk of Acquiring the Environmental Operational Permits Required to Generate Electricity in the DWR's Non-Renewable Contracts

Seller	Seller responsible for operating permits.	DWR pays for operating permits
Allegheny		
Alliance Colton	✓	
Calpeak	✓	
Calpine – 1		
Calpine – 2		
Calpine – 3		
Calpine – 4		
Coral Power	✓	
Dynegy – 1		✓
Dynegy – 2		✓
El Paso		
Fresno Cogeneration	✓	
GWF Energy	✓	
High Desert		
Morgan Stanley		
PacifiCorp		
Sempra		
Sunrise	✓	
Wellhead	✓	
Williams		✓

Note: Some of these contracts have subsequently been renegotiated.

B. Renewable Contracts

Renewable generating facilities face a different set of risks before commercial operation. New renewable facilities sometimes face less uncertainty due to existing environmental regulations than non-renewable power plants. Renewable facilities can be difficult to site, however, often due to local opposition. All of the DWR's renewable contracts that provide for the construction of new generating facilities allow the DWR to terminate the contract if the units do not reach commercial operation by a deadline (discussed in Section 5 on Performance Risk). The Clearwood geothermal contract, however, allows the Seller to claim force majeure if the Seller is unable to acquire the necessary environmental permits to construct the facility.

Unlike fossil power plants, some types of renewable facilities are not required to obtain permits in order to operate; for example, wind, solar, and geothermal facilities generally have a minimal impact on the environment once the plants are built, and these types of facilities are not required to obtain ongoing environmental permits. Other renewable facilities have environmental impacts during operation; for example, biomass and landfill gas plants emit air pollutants, and are therefore required to obtain operational permits. Accordingly, the DWR's landfill gas contract and two of the three biomass contracts explicitly allocate responsibility for acquiring operational environmental permits to the Seller; similar to the natural-gas contracts, the third biomass contract is presumed to allocate the responsibility by default to the Seller.[78]

7.2.2 Risk of Future Changes in Environmental Regulations

The laws and regulations governing the environmental impacts of electricity generation are likely to change within the term of many of the DWR's contracts. In this section, we examine how the DWR contracts allocate the risk of *future changes in environmental regulations*.[79] See Appendix D for a detailed table that summarizes some of the information provided below.

A. Non-Renewable Contracts

Seventeen of the DWR's original twenty long-term non-renewable contracts appear to allocate at least some of the risk of future changes in environmental regulations to the DWR. There are numerous differences in the ways the contracts allocate this risk, however, and there does not appear to be an "industry standard" approach to the treatment and allocation of future environmental compliance risk. The non-renewable contracts can be divided into two broad categories: (1) contracts that only allocate the risk of a future change in regulation that is targeted at energy services, and (2) contracts that allocate the risk of a future change in regulation more generally.[80] There are some circumstances in which environmental regulatory risks are specifically called out, but in other cases these environmental compliance risks are covered implicitly by broader regulatory risk clauses.

Seven of these seventeen contracts (representing 27% of the non-renewable energy under contract) fall within the first category, and only address the risk of a future change in regulation in a limited way.[81] In these cases, the allocation only applies to regulatory changes that are targeted at energy services, and most of the clauses only apply to changes implemented by the State of California. For example, the Wellhead contract states:

> [Wellhead] shall be entitled to pass through to [the DWR] any liability, loss, cost, damage and expense, including gross-up, arising out of a tax or other imposition enacted by the California state legislature after the date of this Agreement that is not of general applicability and is instead directed at the generation, sale, purchase, ownership and/or transmission of electric power, natural gas and/or other utility or energy goods and services. [DWR] shall be entitled to the benefit or reduction of or credit with respect to any such tax or other imposition enacted by the California state legislature after the date of this Agreement. (Wellhead contract 2001, §9.2)

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[78] The Capitol Power and Soledad biomass plants require the Seller to acquire environmental permits, while the Imperial Valley contract does not address the issue explicitly.

[79] The contracts in the DWR sample may not represent the normal allocation of environmental risk in competitive contracts in the electricity industry, because the DWR is part of the government of the state of California. Since governments create environmental compliance risks, the Sellers' perceptions about DWR's ability to influence policymakers may have influenced the allocation of environmental risks in our contract sample.

[80] Appendix D outlines the allocation of environmental risk in all of the DWR contracts.

[81] The Calpeak, Calpine – 4, Coral Power, Fresno Cogeneration, PacifiCorp, Sempra, and Wellhead contracts only explicitly allocate the risk of a future change in regulation in the limited manner discussed here.

It is unclear whether such limited contract clauses (targeted specifically at changes in regulations that directly affect the energy services) would apply (or were intended to apply) to new environmental regulations, or whether these clauses were simply intended to shield the Sellers from windfall profits taxes or other such impositions arising from political dissatisfaction with the electricity industry at the time the contracts were signed.[82] It is clear, however, that the contracts that only allocate the risk of a future change in regulation that is targeted at energy services do not comprehensively allocate environmental compliance risks.

The other ten of the seventeen non-renewable contracts that allocate some of the risk of a future change in regulations to the DWR (representing 63% of the non-renewable energy under contract) fall within the second category. These contracts allocate the risk of a *general* change in regulations, rather than only the risk of regulatory changes that are targeted at energy services. As presented in Table 20, below, these contracts can be grouped into two broad categories based on the treatment of environmental risk: (1) contracts that allocate the cost (sometimes above a threshold) of a new regulation to the DWR, and (2) contracts that require the parties to the contract to negotiate how to share the costs (sometimes above a threshold) of a new regulation. Some of the contracts also restrict the applicability of an environmental compliance risk clause based on the governmental authority that implements the new regulation (e.g., a federal authority versus a state authority).

As shown in the first column of Table 20, eight of the DWR's twenty original non-renewable contracts specifically allocate at least a portion of the costs of new, general environmental regulations to the DWR. There are numerous differences among these contracts:

- The Allegheny contract only passes on to the DWR an increase or decrease in costs due to actions of a *state* governmental authority.
- Three of the Calpine contracts and the Williams contract pass on to the DWR any cost increase (above thresholds of either $0.50 or $5.00 per MWh) due to actions by any governmental entity.[83] The Williams contract provides an example of this comprehensive treatment of environmental risk:

> If [Williams] can demonstrate that its cost of service for this Agreement has been increased by an aggregate amount of $5 per MWh or more since the [date the contract was executed] as a result of any governmental action or inaction *other than by* a [political subdivision or public entity of the State of California], [DWR] shall pay all such increased costs of services in excess of $5 per MWh in the aggregate for the remainder of the delivery term. (emphasis added)
>
> If [Williams] can demonstrate that its cost of service for this Agreement has been increased since the [date the contract was executed] as a result of any governmental action or inaction by a [political subdivision or public entity of the State of California], [DWR] shall pay all such increased costs of services for the remainder of the delivery term.
>
> For the purpose of the preceding two sentences, governmental action that increases the cost of service for this Agreement shall include (a) new taxes (including the imposition or increase in rate

[82] Sellers of electricity were clearly mindful of the possibility that the state might impose a windfall profits tax on the sale of electricity. Two bills were introduced in the Legislature in April 2001 to impose a windfall profits tax, and one bill came within one vote of passing in May 2001 (SB 1xx).

[83] These three Calpine contracts have since been renegotiated (as have others). In the renegotiated Calpine contracts, the DWR only bears the risk of a new regulation targeted at energy goods and services implemented by the California Legislature.

or amount thereof) or (b) the imposition of other unanticipated costs and charges caused by governmental action. (Williams contract 2001, §9.2)

The Williams contract therefore shifts more of the burden of a regulatory change to the DWR if the change is implemented at the State level than if it is implemented by a non-State entity.[84]

Table 20. Explicit Allocation of the Risk of Future Environmental Regulations in the DWR's Non-Renewable Contracts

(Only Applicable to Regulations Imposed by the Governmental Authority in Parenthesis, if Specified)

Seller	Any cost above threshold born by the DWR	Parties will negotiate how to share costs above threshold
Allegheny	No threshold (State)	
Alliance Colton	Unclear*	
Calpeak		
Calpine – 1	Threshold = $5 / MWh	
Calpine – 2	Threshold = 50¢ / MWh	
Calpine – 3	Threshold = 50¢ / MWh	
Calpine – 4		
Coral Power		
Dynegy – 1	No threshold	
Dynegy – 2	No threshold	
El Paso		
Fresno Cogeneration		
GWF Energy		Threshold = $2.5 M / yr; If parties do not successfully negotiate, Seller may terminate.
High Desert		
Morgan Stanley		
PacifiCorp		
Sempra		
Sunrise		No threshold; Parties will negotiate in good faith to leave Seller whole.
Wellhead		
Williams	No threshold (State) $5 / MWh (Federal)	

Note: Blank cells are contracts that do not explicitly allocate the risk of a general future environmental regulation. Also note that some of these contracts have been subsequently renegotiated.
* The Alliance Colton contract states that it is standard practice for contracts to allocate environmental risk in this manner, but it is unclear if the contract itself actually does.

[84] This differentiation may be due to the Seller's perceptions about the DWR's ability to influence policymakers in California.

- The Dynegy contracts simply state that Dynegy "shall not suffer the effects of any costs or restrictions imposed by environmental agencies whenever incurred that are associated with providing" energy under the contracts (Dynegy contracts 2001, §4C). The contracts do not define "environmental agencies."
- The Alliance Colton contract claims that it is standard practice for Sellers to pass at least certain, tax-related regulatory risks on to the purchasers of electricity. The contract states:

  > [Alliance Colton] represents and warrants to [DWR] that (a) it is standard business practice in jurisdictions where sellers in power sales transactions believe there to be political risk, to provide in transactions with non-government entities that future changes in taxes are generally borne by the customer in a power sales transaction; (b) no change in tax law has been included in [Alliance Colton's] Contract Price; and (c) if the taxes that would be paid by [Alliance Colton], other than income taxes, are reduced, then [Alliance Colton] shall pass all of such tax reduction on to [DWR]. (Alliance Colton contract 2001, §10.2 (xiii))

  It is unclear, however, whether this contract actually allocates the risk of a tax increase to the DWR, which is a government entity.

Two additional contracts provide that the parties to the contract will negotiate how to share the costs of a new regulation rather than specifically defining how the costs will be shared in advance. Both of these contracts allocate the risk of a new regulation in large part to the DWR. The GWF Energy contract states that if regulatory changes increase the Seller's costs by more than \$2.5 million in any year (or approximately \$1.00 per MWh) after August 31, 2003, then the Seller can propose to adjust the contract price; if the two parties cannot agree on an adjustment to the contract price, then the Seller can terminate the contract. The Sunrise contract also requires the parties to negotiate how to share the costs of a new regulation. The Sunrise contract's environmental risk clause is only applicable to new state regulations, and it fully allocates the risk of a new state regulation to the DWR:

> In the event that a change in California Law subsequent to the date of this Agreement has the effect of imposing additional costs on [Sunrise] beyond those that would have been imposed prior to such change in California Law, the [DWR] and [Sunrise] shall in good faith negotiate and make changes to this Agreement and/or the payments contemplated hereunder that will have the effect of leaving [Sunrise] no worse off than if the change in California Law had not occurred. (Sunrise contract 2001, §13.04)

The degree to which environmental risks are passed on to the DWR appears to be explained in part by the date on which the specific contracts were executed (see Figure 4, below). The contracts that allocate the risk of any general change in regulations to the DWR were mostly signed by May of 2001, while the contracts that are more favorable to the DWR and only allocate the risk of regulatory changes targeted at energy services to the DWR were signed primarily after May. The allocation of environmental regulatory risk in our contract sample may therefore be explained in part by the relative strength of the DWR's bargaining position over time.[85]

[85] Upon renegotiation, the Calpine – 1, Calpine – 2, and Calpine – 3 contracts were changed from allocating the risk of any general change in regulations to the DWR to only allocating regulatory changes targeted at energy services to the DWR, perhaps reflecting the DWR's strengthened bargaining position during renegotiations relative to when the Calpine contracts were originally signed.

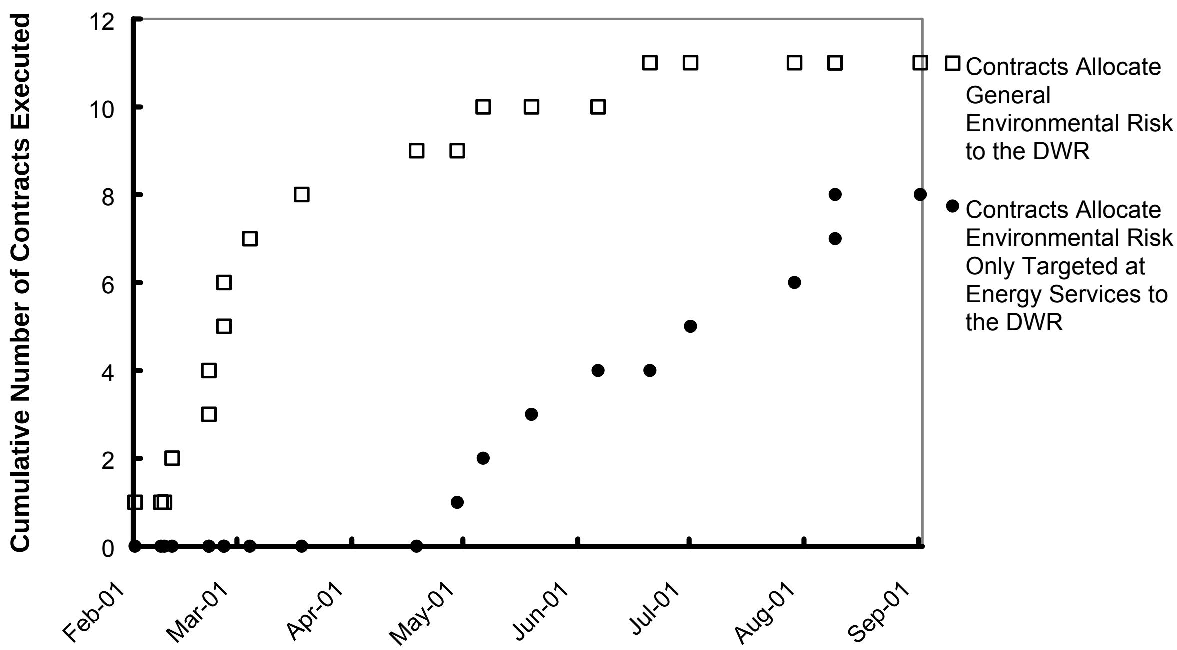

Figure 3. Allocation of Environmental Risk in the DWR's Non-Renewable Contracts by Date of Contract Execution

In the contracts that do not explicitly allocate the risk of a general change in regulations, those risks are implicitly allocated based on the point of power delivery (i.e., the transmission system in the relevant ISO congestion zone). All costs up to the delivery point are born by the Seller, while all costs after the delivery point are born by the DWR (California State Auditor 2001). Thus, as discussed above, the implementation details of a new regulation could have a large effect on which party bears the cost. Of course, if a contract does not explicitly allocate the risk of a new regulation, and one is enacted, it is likely that the parties will litigate the matter.[86] Finally, as with fuel price risk discussed in an earlier section of this paper, even if the Seller clearly bears the environmental risk in a contract, the DWR may still bear some "residual" environmental risk (i.e. bankruptcy risk) if the Seller is excessively exposed to the risk.

Based on the preceding discussion, it is apparent that the DWR may be exposed to significant financial costs if new environmental regulations are implemented; this may be especially true for carbon regulation because the DWR's contracts are predominantly for relatively clean-burning (in terms of criteria pollutants such as NO_x, SO_2, particulates, and mercury) natural gas plants. In the extreme, assume that the DWR bears the cost of carbon regulation for *all* of its non-renewable contracts. If the carbon regulation led to a carbon allowance price of $10 per metric ton, DWR's cumulative additional costs over the 2003-2010 timeframe would range from $855 million (0.15 cents per kWh) if the tax were implemented in 2003 to $108 million (0.02 cents per

[86] A party might try to claim force majeure to avoid the cost of a burdensome new regulation; however force majeure clauses generally exclude economic considerations and would probably only apply to a new regulation that prevents a power plant from operating.

kWh) if the tax were implemented in 2010.[87] Similarly, with a carbon allowance price of $100 per metric ton, the DWR's cumulative exposure from 2003-2019 could range from $8.5 billion (1.5 cents per kWh) if the tax were implemented in 2003 to $1 billion (0.2 cents per kWh) if the tax were implemented in 2010.

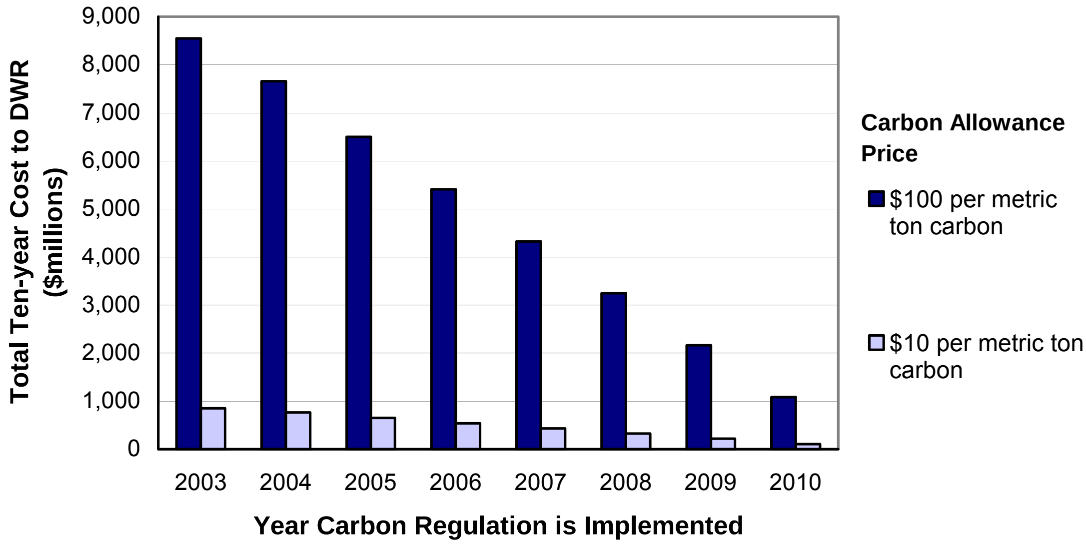

Figure 4. DWR's Potential Exposure to Carbon Emission Regulations (For All Non-Renewable Contracts)

If the DWR is instead assumed to bear the cost of carbon regulation only for the non-renewable contracts that *explicitly* allocate the risk to the DWR (see Figure 6),[88] the DWR's cumulative 2003-2010 cost exposure would be far more limited: $128 million to $12 million (0.05 to 0.005 cents per kWh) if a $10 per metric ton carbon allowance price were implemented in 2003 and 2010, respectively, and $3.1 billion to $356 million (1.2 to 0.14 cents per kWh) if a $100 per metric ton carbon allowance price were implemented in 2003 and 2010, respectively. Though the DWR's direct exposure is far more limited in this case, if the Sellers that do not explicitly allocate environmental compliance risks to the DWR are unable to bear the new cost of carbon regulation, the DWR might be faced with numerous contract defaults.

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[87] Carbon emissions are calculated for all of the non-renewable contracts assuming an average emission rate for natural gas generation of 160.79 metric tons of carbon per GWh (DOE and EPA 2000). For various estimates of carbon allowance prices, see EIA (2001a and 2001b), Weyant (2000), and Interlaboratory Working Group (2000).

[88] Since carbon regulation would most likely be implemented by a federal governmental authority, only the Calpine – 1, Calpine – 2, Calpine – 3, Dynegy – 1, Dynegy – 2, GWF Energy, and Williams contracts allocate the risk to the DWR. (Some of these contracts require both parties to share the cost.) If carbon regulation were considered to be 'targeted at energy services' then the Calpeak, Coral Power, and Pacificorp contracts would allow the Sellers to terminate the contracts.

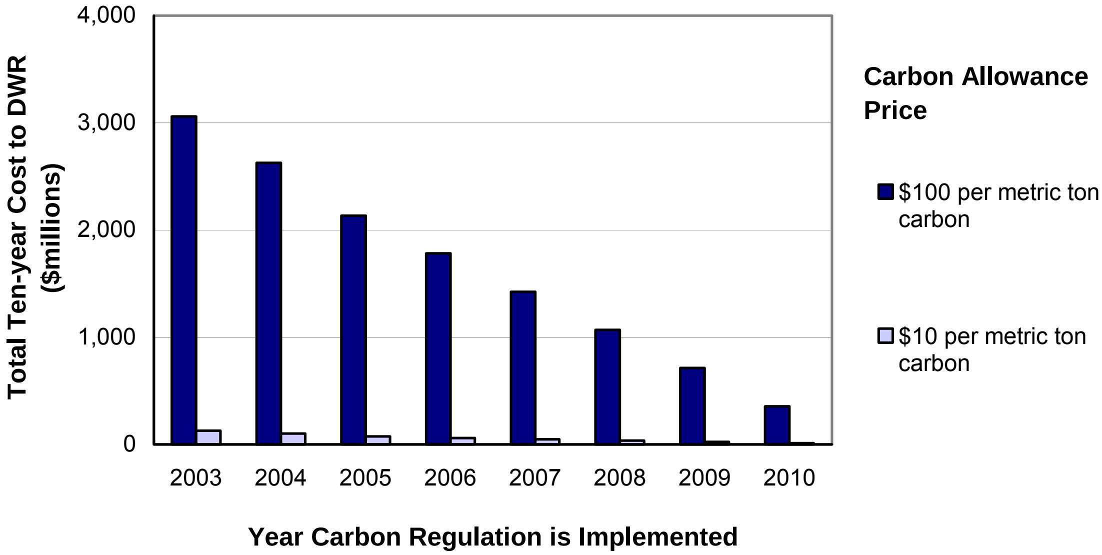

Figure 5. DWR's Potential Exposure to Carbon Emission Regulations (Only For Non-Renewable Contracts that Explicitly Allocate the Risk to the DWR)

Although more stringent national regulation of sulfur dioxide, nitrogen oxides, and mercury emissions from power plants is possible, and even likely, a 'back-of-the-envelope' calculation suggests that such regulations would not expose the DWR to significant costs. Using a scenario developed by the Energy Information Administration (EIA) of federal legislation to decrease emissions of these three pollutants from power plants by 75% by 2012 (EIA 2001b), but focusing on nitrogen oxides, the potential cost to the DWR from all of its non-renewable contracts is approximately $100 million (or 0.02 cents per kWh) through 2010.[89] However, it is unclear how additional regulation of nitrogen oxides would affect current emissions reduction programs in California, which already have emission allowance prices that can be higher than the EIA predicts in its scenario.

B. Renewable Contracts

Only one of the DWR's seven original renewable energy contracts explicitly allocates the risk of a future change in regulations. In particular, the original Soledad biomass contract allocates the risk of any state-implemented change in regulation to the DWR. Because generating electricity from renewable resources considerably mitigates environmental compliance risks, the parties to the DWR's renewable contracts may not have considered the risk of future environmental regulations to be a significant enough concern to warrant allocation in the contracts.

If new environmental or renewable energy regulations are enacted, however, the question of which party to a renewables contract receives the benefits of the renewable plant's

[89] Sulfur dioxide and mercury emissions are not a large concern for natural gas-fired power plants. We assume emission rates of 0.45 lbs of nitrogen oxides per MWh for existing power plants, 0.31 lbs per MWh for new simple cycle plants, and 0.06 lbs per MWh for new combined cycle plants (CEC 2001). We linearly extrapolated EIA's nitrogen oxides emission allowance prices for each year through 2010. This scenario is an extreme case, as it assumes the cost of future nitrogen oxides regulation falls exclusively on the DWR, which is clearly not the case.

environmental performance may arise. At the time of contract execution, the possibility of a state renewables portfolio standard (RPS) should have been of particular concern. An RPS requires providers of electricity to purchase a minimum quantity of renewable energy. An RPS was in fact adopted in California subsequent to the DWR's execution of its long-term contracts.

An important question under California's new RPS is which party in the DWR's contracts receives credit for the renewable attributes of the underlying electricity? Here it is useful to consider the output of a renewable plant to include two separable commodities: the electricity itself and the renewable energy credits (RECs) associated with the electricity. The commodity electricity is typically considered to be equivalent to electricity generated from any other source, while the RECs contain the value of having generated the electricity from renewable sources rather than conventional sources (i.e., the renewable energy attributes). Generators of renewable electricity can unbundle the electricity and RECs and sell them separately. Accordingly, if the purchaser of electricity from a renewable power plant does not take ownership of the RECs, then the purchaser cannot claim to be buying renewable energy.

Only two of the DWR's long-term renewable contracts explicitly allocate the associated RECs. Specifically, in the two wind contracts the Sellers retain all rights to "the renewable attributes, emission reductions or credits (offsets) relating to the project" (PG&E Energy Trading 2001). PG&E National Energy Group subsequently marketed these RECs to other parties, clearly illustrating that the DWR will not be able to benefit from the renewable nature of its contract with PG&E unless it acquires the RECs (Green Power Network 2001). For the remaining contracts (that do not specifically allocate RECs), it is assumed that the DWR receives the RECs by default. This issue might, however, be subject to litigation if RECs gain significant value due to California's new RPS.

Accordingly, although the DWR originally signed a total of seven long-term contracts with producers of renewable energy, the DWR can only truly claim to have five contracts for renewable electricity, supplying 0.5% of the total energy under contract in the coming decade.

Now that an RPS has been passed into law in the state, it is useful to consider what value the DWR forfeited when it chose not to take the RECs associated with its two largest renewable contracts, the two wind contracts. Under California's RPS, the large investor-owned utilities are required to increase the percent of their electricity sales from renewable energy by at least 1% each year. DWR's energy purchases are to be included in calculating renewable energy purchase obligations. Assuming that the "above-market" cost of renewable energy equals 0.75 cents/kWh and that RECs sell for the same price, the DWR will lose $40 million in value by forfeiting the RECs in its two wind contracts. If REC price instead equals 1.5 cents/kWh, this value would double to $80 million. This clearly shows that a seemingly minor clause in two of DWR's contracts may well cost the state's ratepayers a sizable amount of money.

7.3 Summary of Environmental Risk

Renewable and natural gas-fired electricity contracts have very different environmental risk profiles by the nature of the technologies and fuel sources used to generate the electricity. If new environmental regulations are enacted, parties to fossil-fuel based contracts will most likely have to bear additional costs, while parties to renewable contracts may realize financial benefits (at least in the case of an RPS). These relative risks and costs should be considered in the resource selection process.

Given the potential financial impact of a new environmental regulation, it is perhaps surprising that a number of the DWR's natural-gas contracts do not explicitly address and allocate environmental risk in a comprehensive way. This lack of attention to environmental compliance risk may be attributed to either a lack of concern about the cost of future environmental regulations or a lack of awareness of their potential cost.

Those contracts that do explicitly allocate environmental compliance risk shift much of that risk to the DWR, though not in a consistent fashion. There is no apparent "industry standard" way to allocate environmental compliance risks.

For the many natural-gas contracts that do not explicitly and comprehensively address environmental compliance risks, the risks presumably fall on the Seller. However, in these cases, future environmental regulations could result in costly legal battles and/or contract defaults, shifting some of the risk implicitly to the DWR.

As a whole, the DWR is clearly exposed to environmental compliance risk in its long-term electricity contracts; this is especially true for the risk of carbon regulation. Moreover, while renewable energy can be used to mitigate such risks, the DWR's decision not to purchase the RECs associated with its two largest renewable energy contracts will reduce the risk mitigation value of the DWR's renewable energy purchases.

8 Regulatory Risk in Electricity Contracts

California's electricity industry is regulated by agencies at both the state and federal levels. Over the past decade, California's electricity industry has been subject to a great deal of regulatory uncertainty – from the roots of the movement to restructure the electricity industry, to the crisis of 2000 and 2001, to the industry's subsequent state of limbo. Both renewable and non-renewable contracts face similar regulatory uncertainties.

Given California's particularly tumultuous recent history, the contracts in the DWR sample may not represent the standard allocation of regulatory risk in electricity contracts. The parties selling electricity to the DWR were clearly aware that they faced a substantial amount of regulatory risk for at least three reasons: (1) the contracts were signed at the height of California's crisis, (2) the contract prices are relatively high, and (3) the DWR is a government agency and therefore might be able to influence regulatory decisions to a greater degree than could a "regular" counterparty to an electricity contract.

8.1 Regulatory Risk Fundamentals

We define regulatory risk as the possibility that future laws and regulations will alter the benefits or burdens of an electricity contract. Excessive regulatory risk can have dire consequences on an electricity market. For example, many have blamed the tight supply - demand conditions that existed in California's electricity market during the crisis on the utilities' decisions not to build significant amounts of new generation capacity during the 1990s because the utilities faced excessive regulatory uncertainty.

Regulatory risk can be divided into two broad categories: (1) the possibility of changes in general regulations or laws that would affect an electricity contract, for example, a nationwide carbon tax, and (2) regulatory requirements targeted at a specific contract, for example, a FERC ruling to modify a contract's price.

The first category of broad regulatory changes that would affect – but not be targeted at – specific electricity contracts is not discussed in this chapter. These broader regulatory risks were covered, in part, with our discussion in Section 7 on Environmental Risk; environmental regulations are among the most likely future regulatory changes in this category, and are potentially among the most costly for the parties to an electricity contract. In this section we discuss only the second category of regulatory risk: regulatory requirements targeted at specific contracts.

Parties to an electricity contract can take two approaches in managing regulatory risk. First, contracts can try to prevent regulatory action. Regulatory agencies have both rule-making authority to create new regulations, and adjudicatory authority to rule on existing regulations and electricity contracts. Electricity contracts can contain clauses to try to prevent regulatory agencies from exercising this latter, adjudicatory role. Second, if a regulatory authority requires a change in a contract, the contract can try to mitigate and allocate the consequences of the regulatory requirement.

Two principal regulatory authorities regulate California's electricity industry: the Federal Energy Regulatory Commission (FERC) at the federal level, and the California Public Utilities Commission (CPUC) at the state level. The FERC has regulatory jurisdiction over the wholesale electricity market in California and the contracts signed by the DWR. The FERC is required by Section 206 of the Federal Power Act (FPA) to ensure that wholesale rates are "just and reasonable" (16 U.S.C. 824e); FERC therefore has the authority to change contract prices or terms that it determines to be unjust or unreasonable, and to abrogate contracts entirely. The California Public Utilities Commission has regulatory authority over retail electricity rates and the investor-owned utilities in California; at the time the DWR contracts were signed, it was unclear what regulatory oversight the CPUC would have over the DWR's contracts.

8.2 Regulatory Risk in the DWR Contract Sample

Regulatory challenges to the DWR contracts began shortly after the contracts were signed: both the CPUC and the Electricity Oversight Board filed complaints with FERC, asking the agency to modify or abrogate the DWR contracts (CPUC 2002; EOB 2002), and FERC agreed to hear the complaints (FERC 2002).[90]

About half of the DWR's original non-renewable (primarily natural gas) contracts prevent the parties to the contracts (the seller and the DWR) from seeking changes in the contracts from a regulatory authority. Meanwhile, almost all of the non-renewable contracts designate a course of action that the parties will take if a regulatory agency orders a change in the contract.

In contrast, none of the renewable contracts attempt to prevent regulatory review of the contracts, and only two of the seven renewable contracts designate a course of action that will be taken if a regulatory agency orders a change in the contract. Though both renewable and natural-gas contracts presumably face the same or at least very similar regulatory risks, the treatment of these risks in the renewable contracts is not nearly as formal as in the natural gas contracts.

A. Non-Renewable Contracts

Undoubtedly, the best way parties to an electricity contract can mitigate regulatory risk is to ensure that the contract price and terms are "just and reasonable" in the first place. Arguably, this may not have been the primary strategy used by some of the Sellers of the DWR contracts, as demonstrated by the extremely high prices in some of the contracts. Instead, the DWR contracts try to prevent regulatory review of the contracts, and mitigate and allocate the consequences of future regulatory requirements.

The DWR's non-renewable contracts use two strategies to attempt to prevent regulatory review of the contracts, as shown in Table 21. First, thirteen of the twenty original non-renewable contracts explicitly prevent the parties to the contract from seeking a change in the contract from a regulatory authority. Second, eleven of the twenty non-renewable contracts state that the parties to the contract agree that the contract is "just and reasonable."

[90] The CPUC has dropped its complaint with regards to the Sellers that have renegotiated their contracts with the DWR.

Table 21. Contract Clauses to Prevent Regulatory Review in the DWR's Non-Renewable Contracts

Seller	Party prevented from seeking change in contract from a regulatory authority (given in parentheses, if specified in contract)	Contract states that the price is just and reasonable (for purposes of regulatory authority in parentheses, if specified in contract)
Allegheny	Both parties	✓ (FERC)
Alliance Colton		
Calpeak	Both parties (FERC)	✓ (FERC)
Calpine – 1	Both parties (FERC)	✓ (FERC)
Calpine – 2	Both parties (FERC)	✓ (FERC)
Calpine – 3	Both parties (FERC)	✓ (FERC)
Calpine – 4	Both parties (FERC)	✓ (FERC)
Coral Power	Both parties (FERC)	
Dynegy – 1	DWR (CPUC)	✓ (CPUC)
Dynegy – 2	DWR (CPUC)	✓ (CPUC)
El Paso		
Fresno Cogeneration	Both parties	
GWF Energy	Both parties	
High Desert		
Morgan Stanley		
PacifiCorp		✓ (CPUC)
Sempra		✓ (FERC)
Sunrise		
Wellhead	Both parties	
Williams	Both parties (FERC)	✓

* Note: A number of these contracts have subsequently been renegotiated.

In addition to these contract clauses, all but three of the original non-renewable contracts specify a course of action for the parties to take if a regulatory authority orders a change in the contract. Many contracts also specify different courses of action depending on who instigated the regulatory change (e.g. one of the parties to the contract, the State of California, etc.). Most of the contracts try to mitigate the effect of a regulatory authority's requirement to modify the contract, and some contracts allocate this risk by shifting the burden to one party or the other.

Specifically, eight of the twenty original non-renewable contracts stipulate that the contract price will not change, even if a regulatory authority orders that it change (see Table 22, below).[91] Thirteen of the twenty non-renewable contracts stipulate that, in the face of a required regulatory change to the contract, the parties will use their best efforts to reform the agreement in order to give effect to the original intention of the parties; this clause is contained in the EEI contract

[91] The CPUC's Section 206 complaint to the FERC challenges the notion that a contract can circumvent a regulatory order by requiring the contract price to stay the same regardless of regulatory action (CPUC 2002).

template. Five of the DWR's non-renewable contracts allocate the risk of a required change in the contract by shifting the burden primarily to one party. As shown in Table 22, the two most extreme contracts stipulate that the DWR will default on the contract, requiring a large upfront termination payment to the Seller,[92] if an agency of the State of California, in one case, or the California Legislature, in another case, instigates a regulatory review of the contract that results in a requirement to change the contract.

Table 22. Courses of Action to be Taken by Parties to a Contract if a Regulatory Authority Orders a Change in the Contract

(Only Applies to Regulatory Review Instigated by Party in Parentheses, if Specified)

Seller	Contract price will not change	Parties use best efforts to reform agreement to give effect to original intention of parties.	DWR defaults	Seller can terminate (with no termination payment)	Adversely affected party may terminate or re-negotiate contract
Allegheny	✓ (either party)	✓			✓
Alliance Colton		✓			
Calpeak	✓				
Calpine – 1	✓ (State of CA)	✓			
Calpine – 2	✓	✓			
Calpine – 3					
Calpine – 4	✓	✓			
Coral Power		✓	✓ (CA Legislature)	✓ (non-State)	
Dynegy – 1		✓			
Dynegy – 2		✓			
El Paso		✓			
Fresno Cogeneration					
GWF Energy	✓ (State of CA)			✓ (non-State)	
High Desert	✓ (CA Legislature)	✓			
Morgan Stanley		✓			
PacifiCorp			✓ (State of CA)	✓ (non-State)	
Sempra					✓
Sunrise		✓			
Wellhead					
Williams	✓ (State of CA)	✓			

* Note: Some of these contracts have subsequently been renegotiated.

[92] The termination payment is equal to the difference between the present value of the remaining term of the existing contract and a replacement contract.

B. Renewable Contracts

Although the DWR's original renewable contracts are certainly not immune to regulatory risk, almost none of these contracts contain clauses related to regulatory risk. None of the renewable contracts seek to prevent regulatory review of the contracts, and only two of the seven contracts outline a course of action if a regulatory authority requires a change in the contract. The two wind contracts, in particular, contain the regulatory risk clause from the EEI template, which requires the parties to use their best effort to reform the agreement to give effect to the original intention of the parties if a regulatory authority has ordered a change in the contract. The renewable contracts' lack of attention to regulatory risk may be attributed to either a lack of awareness about the potential risk, or else confidence in the "just and reasonable" nature of the contract terms.

8.3 Summary of Regulatory Risk

A contract legally binds two parties to an agreement and provides increased certainty about the future. Thus, it is expected that parties to an agreement will try to minimize the ability of outside parties to change the terms of the contract. In the electricity industry, regulatory agencies do have some authority to change the terms of electricity contracts to which they are not directly a party.

The DWR's non-renewable contracts contain many provisions to try to decrease exposure to regulatory risk by both seeking to prevent regulatory review of the contracts, and by specifying a course of action if a regulatory agency requires a change in a contract. In contrast, very few of the DWR's renewable contracts contain provisions related to regulatory risk.

It deserves reiteration, however, that the treatment of regulatory risk in the DWR contract sample may not represent the standard management of regulatory risk in the electricity industry. The parties selling electricity – especially high-priced non-renewable electricity – to the DWR were clearly aware that they faced an unusual amount of regulatory risk. The strength of the various clauses the DWR contracts use to address regulatory risk will continue to be tested at the FERC.

9 Conclusions

Natural gas-fired and renewable generation technologies have inherently different risk profiles. The allocation of these risks in electricity contracts results in substantially different risk burdens for each party to a contract.

Of the risks analyzed in this paper, renewable energy contracts provide the most value relative to natural gas by mitigating fuel price and environmental risks, while natural gas contracts provide value by reducing short-term demand risk. Renewable sources and natural gas generation face different challenges with regards to fuel supply risk. Natural gas-fired power plants are more vulnerable to systematic interruptions in fuel supply (affecting many plants simultaneously), while renewable generation is more vulnerable to unsystematic day-to-day variability in fuel supply. Prioritizing the relative importance of these systematic and unsystematic risks is somewhat subjective and will depend on the overall portfolio of fuel supplies that is used to generate electricity. Our contract sample also suggests that gas-fired generation may mitigate certain performance risks relative to renewable electricity; this finding may be limited to the DWR contracts, however, because, in principal, performance risks could be handled equivalently between renewable and natural gas generators. Finally, neither natural gas nor renewables has a clear advantage with regards to regulatory risk.

The DWR's long-term electricity contracts, upon which our analysis in this report is based, will largely define California's electricity system over the coming decade. The DWR contracts provide for the construction of a significant amount of new natural gas-fired power plants, which will increase California's reliance on natural gas. This may have important implications for the vulnerability of California's economy to natural gas price volatility and possible systematic interruptions in natural gas supply. In addition, the State Auditor expressed concern that the DWR's original contract portfolio included excessive non-dispatchable contracts and insufficient dispatchable contracts. Several of the contracts were subsequently renegotiated to increase dispatchability, among other changes.

Our analysis of the allocation of risks in the DWR contracts also illuminates the risks that the DWR – and thereby California's ratepayers and taxpayers – will bear over the next decade. The DWR directly bears fuel price risk for about 40% of the electricity under its original contracts, and bears most of the fuel supply risk in the contracts. The contracts contain numerous penalties and incentives to try to reduce performance risk, and a substantial amount of this risk is allocated to the Sellers because many elements of performance risk are within the Sellers' control. Demand risk is primarily allocated to the DWR, though the dispatchable natural gas contracts reduce the DWR's demand risk. Environmental regulatory risk is not uniformly addressed in the contracts, however the contracts that do explicitly allocate environmental risk predominantly allocate it to the DWR. Finally, the DWR and the Sellers generally share regulatory risks, though a number of the contracts allocate the majority of this risk to the DWR. As we have shown, the DWR could be exposed to billions of dollars in additional costs due to its exposure to fuel price and environmental compliance risks.

As we have noted throughout this paper, certain aspects of the DWR contract sample may not be representative of competitively bid long-term electricity contracts. The DWR has renegotiated a number of the contracts, primarily strengthening terms and conditions related to performance risks, increasing dispatchability, and shortening contract lengths and reducing contract prices. This finding increases our confidence that the original DWR contracts' treatment of the risks that are most relevant to our comparison of natural gas-fired and renewable electricity contracts (that is, fuel price and supply risk, demand risk, and environmental risk) may not have been influenced as strongly by the particular circumstances of the crisis period in which the contracts were executed, and can thereby provide insight into the risk allocation and mitigation practices common in the electricity industry.

Although all of the risks discussed in this paper are important, it is sometimes unclear whether utilities and other parties that procure electricity objectively analyze the trade-offs between all of the various risks we have discussed. Utilities, for example, appear to place a particular emphasis on demand and performance risks, which favors investment in natural gas generation technologies. Historically, less emphasis seems to have been placed on fuel price and environmental compliance risks, which might otherwise favor renewable technologies. As we discussed, to reduce demand risk only a portion of a portfolio of electricity supplies must be dispatchable, so there may be significant opportunities for investments in natural gas and renewables to complement each other within a particular resource portfolio. A better understanding of the risks and risk allocation practices associated with the use of renewable and natural gas-fired electricity may help utilities (and others that procure power) make more objective investment decisions in the future.

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Appendix A: Glossary

As-available As-available contracts allow the power plant to sell electricity whenever it is able to generate.

Availability Availability is generally used in dispatchable contracts to mean the number of hours that the generation unit was available to generate power during a period, divided by the total possible number of hours the unit could have been dispatched during the period as specified in the contract (adjusted for force majeure events and scheduled outages).

Baseload contracts Baseload contracts (7x24) can supply power all day every day.

Capacity charge The amount a Seller of a dispatchable contract is paid to be available to generate electricity (separate from a fuel or energy charge for the electricity that is actually generated).

Commercial operation deadline The deadline for a Seller to complete construction of a power plant, after which penalties may be assessed.

Cover damages If a Seller fails to deliver scheduled energy and the failure is unexcused, then the Seller pays for the DWR's incremental cost of replacement energy; if the DWR fails to receive scheduled energy, then the DWR pays the Seller the difference between the contract price and the amount the Seller was able to sell the energy for. (What events qualify as excused outages depends on the firmness of the contract.)

Default Contracts define under what conditions a party will default on a contract; these conditions usually include failure to perform any material obligation in the contract or entering into bankruptcy. When a party defaults on a contract, the contract is terminated and the defaulting party must pay the non-defaulting party a termination payment.

Demand risk The risk that the electricity that has been contracted for will not be needed as anticipated, or that there will not be enough electricity to meet fluctuating demand.

Dispatchable contracts Dispatchable contracts allow the DWR to choose the amount of electricity to be generated at any given time, within limits set in the contract.

Environmental risk The financial risks to which parties to an electricity contract are exposed, stemming from both existing and possible future environmental regulations.

Excused outage During an excused outage, the Seller is not required to deliver scheduled electricity and is not penalized for failing to deliver.

Firm electricity contracts Firm electricity contracts generally only excuse the Seller from delivering scheduled electricity during events of force majeure.

Firm gas contracts Firm natural gas contracts provide continuous service, whereas interruptible gas contracts allow the distributing company to curtail service under certain circumstances, as specified in the contract.

Firmness The firmness of an electricity contract determines what events qualify as excused outages. In the DWR contract sample, all contracts are either firm or unit-contingent.

Fixed-price contract In a fixed-price electricity contract, the price per MWh of electricity is set in the contract. In some contracts the price is fixed throughout the term of the contract, and in other contracts the price varies according to a fixed schedule.

Force majeure An event of force majeure is defined in the EEI contract template as a circumstance that prevents a party from performing its obligations, that is not within the reasonable control of (or the result of negligence of) the party, and which the party cannot overcome by the exercise of due diligence. Force majeure is commonly used in legal contracts to absolve parties of responsibility during catastrophes, however, some contracts expand on the definition of force majeure. During an event of force majeure, the Seller is excused from delivering power.

Forced outage A forced outage is defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines as an outage resulting from an immediate mechanical, electrical, or hydraulic control system trip or an operator-initiated trip in response to an alarm.

Fuel price risk The risk that the price of the fuel used to generate electricity will exhibit variability (positive or negative), resulting in an uncertain cost to generate electricity.

Fuel supply risk The risk that the fuel supply to a power plant will be unreliable, resulting in the inability to generate electricity in a predictable and dependable manner.

Heat rate A measure of how efficiently a power plant uses fuel to generate electricity. (Usually measured in Btu per kWh.)

Imbalance charge Penalties potentially assessed by an ISO or utility on electricity suppliers who deliver less (or more) electricity than they had scheduled.

Intermittent The pattern of electricity generation associated with certain, primarily renewable (e.g. wind and solar), technologies that cannot be completely predicted or controlled. Generation is contingent upon resource availability.

Interruptible gas contracts Interruptible natural gas contracts allow the distributing company to curtail service under certain circumstances, as specified in the contract, whereas firm contracts provide continuous service.

Long-term contract We define long-term contracts to be three years in length and longer.

Must-take electricity Electricity that is sold in non-dispatchable contracts, in which the Buyer must take and pay for the electricity specified in the contract whether or not it is actually needed.

Net short The “net short” in California is the difference between the electricity demanded by the utility customers, and the electricity supplied by utility-owned generation and qualifying facilities under contract with the utilities.

Non-dispatchable contracts Non-dispatchable contracts (also known as “must-take” or “take-or-pay”) require the Buyer to pay for, and the Seller to provide, all the electricity as scheduled in the contract.

Non-renewable contracts In this paper, non-renewable contracts include contracts for electricity generated from natural gas and contracts that do not specify what resources will be used to generate the electricity under contract (but that will most likely use predominantly non-renewable resources, especially natural gas).

O&M charge The amount a Seller of a dispatchable contract is paid for the operations and maintenance associated with their generating electricity.

Partially dispatchable contracts Partially dispatchable contracts require the Buyer to take a minimum amount of electricity, and allow the Buyer to dispatch the generation facility in limited ways.

Peak electricity products Peak products (6x16) generally can supply power from 6 am to 10 pm, Monday through Saturday.

Performance risk Performance risk refers to the willingness and ability of the supplier to deliver electricity according to the contractually prescribed requirements in terms of time and quantity.

Regulatory risk The risk that future laws or regulations, or regulatory review of a contract, will alter the benefits or burdens of an electricity contract to either party.

Renewable energy credit Renewable energy credits reflect the value of having generated electricity from renewable rather than non-renewable sources. Renewable energy credits can be traded separately from electricity.

Renewables portfolio standard (RPS) A policy that requires providers of electricity to sell a minimum percentage of electricity generated from renewable resources.

"Residual" fuel price risk The risk of a Seller's bankruptcy or contract default that the DWR still bears due to fuel price risk in fixed-price natural gas-generated electricity contracts.

Summer super peak electricity products Summer super peak products (5x8) generally can supply power for 8 hours per day, 5 days a week, from June through October.

Systematic risk A systematic risk is a risk that affects all members of a group simultaneously; the risk that an individual member of the group faces is therefore correlated with the risk faced by the other members of the group.

Take-or-pay contracts See Must-take electricity.

Termination payment In an event of contract default, the defaulting party pays a termination payment to the non-defaulting party. The termination payment in the DWR contracts is equal to the difference between the present value of the existing contract and a replacement contract.

Tolling agreement In a tolling agreement, the Buyer pays for the cost of natural gas, pays the generator a fee to reserve the use of the generation facility, and pays operating charges when the facility generates power.

Unit A single generation unit or power plant. Contracts often provide electricity from a group of generating units.

Unit-contingent contracts Unit-contingent electricity contracts generally excuse the Seller from delivering power when the Seller's generating facilities are unavailable either due to a forced outage, or to an event that was not anticipated as of the date the contract was executed, and that is not within the reasonable control of (or due to the negligence of) the Seller. Unit-contingent contracts also excuse the Seller's performance during an event of force majeure.

Unsystematic An unsystematic risk affects an individual member of a group and is uncorrelated with the risk that the same event or outcome will affect other individuals.

Appendix B. Principal Terms of the DWR Long-term Contracts, Listed by Date of Execution

Seller	Date Contract Signed	Term (years)	Pricing Structure	Product	Dispatchable?	New Units?	Resource[§]	Delivery Point[†]	MW Range	Ten-year Energy Purchases (GWh)[‡]	Price Range ($ / MWh)[‡]	Ten-Year Power Cost ($ millions)[‡]
Calpine – 1	2/6/2001	10	Fixed	Base	No	No	Unspecified	NP 15	200 - 1,000	64,596	59	3,785
El Paso	2/13/2001	5	Fixed	Peak	No	No	Unspecified	NP 15, SP 15	100	2,441	115 - 127	295
Morgan Stanley	2/14/2001	5	Fixed	Base	No	No	Unspecified	SP 15	50	2,136	96	204
Williams	2/16/2001	10	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	175 - 1,400	56,535	63 - 87	3,779
Calpine – 2	2/26/2001	10	Fixed	Peak	No	Yes	Natural gas (CC)	TBD by Seller	200 - 1,000	70,115	115 - 61	4,322
Calpine – 3	2/26/2001	20	Fixed	Base	Yes	Yes	Natural gas (SC)	NP 15	90 - 495	8,001	174 - 154	1,337
Dynegy – 1	3/2/2001	4	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	200 - 600	14,246	120	1,702
Dynegy – 2	3/2/2001	4	Tolling	Base, Peak	Partially	No	Natural gas (CC)	SP 15	200 - 1,500	21,174	145 - 79	2,008
High Desert	3/9/2001	8	Fixed	Base	No	Yes	Natural gas (CC)	SP 15	840	51,896	58	3,010
Imperial Valley	3/13/2001	3	Fixed	Base	No	No	Biomass	SP 15	16	362	100 – 90	34
Allegheny	3/23/2001	11	Fixed	Base, Peak	No	No	Natural gas (CC)	SP 15	150 - 1,000	63,898	61	3,909
Alliance Colton	4/23/2001	10	Tolling	Peak	Partially	Yes	Natural gas (SC)	SP 15	80	1,468	379 - 141	253
Soledad	4/28/2001	5	Fixed	Base	No	Re-power	Biomass	NP 15	13	410	80 – 84	34
Sempra	5/4/2001	10	Tolling > 2002	Base, Peak	No	Yes	Natural gas (SC and CC)	SP 15	400 - 1,900	93,325	160 - 57	6,238
GWF Energy	5/11/2001	10	Tolling	Peak	Yes	Yes	Natural gas (SC and CC)	NP 15	340 - 430	23,713	295 - 44	1,689
Coral Power	5/24/2001	11	Tolling > 2005	Base, Peak	Partially	Yes	Natural gas (SC)	NP 15, and TBD by Seller	275 - 850	28,677	249 - 57	2,292
PG&E Energy Trading	5/31/2001	10	Fixed	Intermittent	No	Yes	Wind	SP 15	67	2,017	59	118
Calpine – 4	6/11/2001	3	Tolling	Peak	Yes	Yes	Natural gas (SC → CC)	NP 15	180 - 225	3,024	134 - 84	322
Clearwood	6/22/2001	10	Fixed	Base	No	Yes	Geothermal	NP 15	25	1,692	67	114
Sunrise	6/25/2001	10	Tolling	Summer Super Peak, Base	Yes	Yes	Natural gas (SC → CC)	SP 15	325 - 560	38,888	228 - 59	2,218

Seller	Date Contract Signed	Term (years)	Pricing Structure	Product	Dispatchable?	New Units?	Resource§	Delivery Point†	MW Range	Ten-year Energy Purchases (GWh)‡	Price Range ($ / MWh) ‡	Ten-Year Power Cost ($ millions) ‡
PacifiCorp	7/6/2001	10	Tolling > 2002	Base	Yes > 2002	Yes	Natural gas (CC)	NP 15	150 - 300	21,900	70**	1,533
Whitewater	7/12/2001	12	Fixed	Intermittent	No	Yes	Wind	SP 15	108	3,263	60	196
Fresno Cogeneration	8/3/2001	10	Tolling	Peak	Yes	Yes	Natural gas (SC)	NP 15	21	950	179 - 92	100
Calpeak	8/14/2001	10	Tolling	Summer Super Peak	Yes	Yes	Natural gas (SC)	NP 15, SP 15	342	5,027	114 - 66	398
Wellhead	8/14/2001	10, option to extend to 20	Tolling	Peak	Yes	Yes	Natural gas (SC)	NP 15	92	4,047	142 - 78	354
Capitol Power	8/23/2001	5	Fixed	Base	No	Re-power	Biomass	NP 15	15	590	119 – 109♦	67
County of Santa Cruz	9/13/2001	5	Fixed	Base	No	Yes	Landfill Gas	NP 15	3	112	65	7
									TOTAL	**584,506**		**40,323**

Note: only DWR contracts signed before October 2001 and with terms of three years and longer are included in this table. A number of these contracts have subsequently been renegotiated or even terminated; the "final" contract terms are not reflected in this table. Totals may not equal sum of components due to independent rounding.
§ CC = combined cycle; SC = simple cycle; SC → CC = simple cycle facility to be converted to combined cycle at some point during the term of the contract.
† NP 15 is the ISO congestion zone north of Path 15; SP 15 is the ISO congestion zone south of Path 15. Path 15 is the main transmission connection between the northern and southern parts of California; it is rated to carry 3,750 MW of power, but it is often congested (Western Area Power Administration 2002).
‡ Figures derived from spreadsheets provided by the State Auditor's office that were used in the State Auditor's report on the DWR contracts (California State Auditor 2001). All dollars are in nominal dollars. Ten-year energy purchases is the amount of electricity to be provided by each contract through 2010, and assumes the DWR purchases the maximum amount of energy available under each contract. Ten-year power cost is the total cost of the ten-year energy purchases.
** This contract is fixed price only until 2003. After 2003 the contract is tolling, but the State Auditor's report did not include a price estimate for this period.
♦ This is the price included in the State Auditor's report, although the contract states a fixed price of $89 per MWh.

Appendix C. California Natural Gas Price Forecast Scenarios

California Natural Gas Price Forecast Scenarios and Total Cost to the DWR

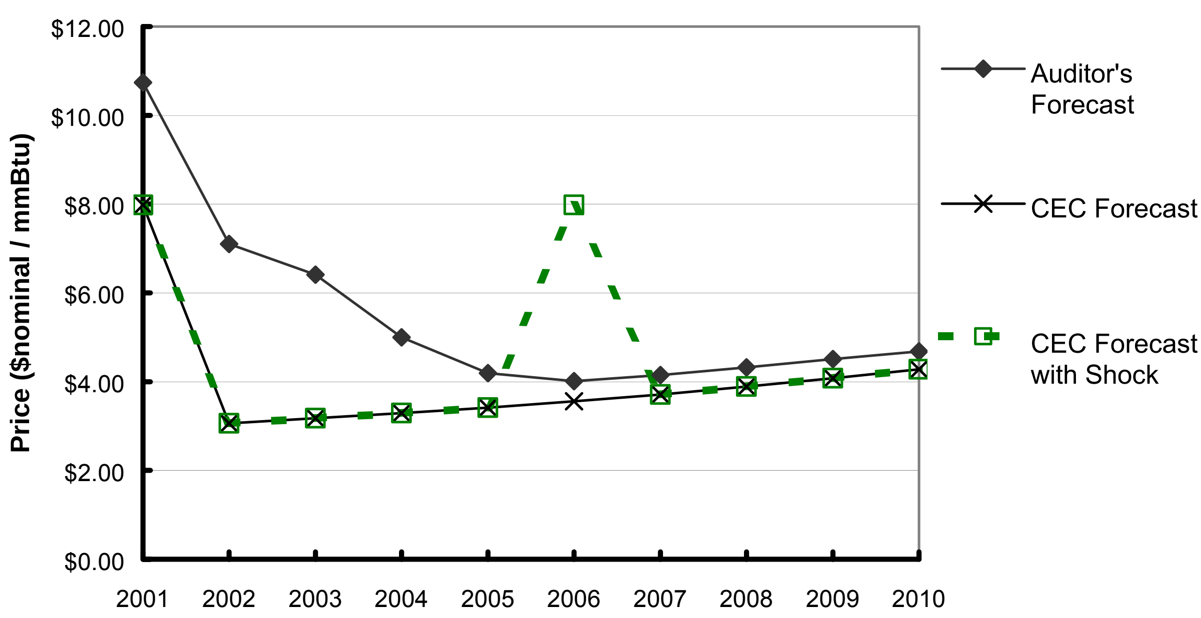
($nominal / mmBtu)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	DWR Ten-year Power Cost ($millions)
Auditor's Forecast[1]	10.74	7.10	6.41	5.00	4.19	4.01	4.15	4.32	4.51	4.68	40,323
CEC Forecast[2]	7.98*	3.06	3.18	3.29	3.42	3.56	3.71	3.89	4.08	4.28	38,270
CEC Forecast with Shock[3]	7.98*	3.06	3.18	3.29	3.42	7.98	3.71	3.89	4.08	4.28	39,977

1. Forecast used by the California State Auditor (2001). Forecast created by DWR's consultant, Navigant Consulting, 25 July 2001.
2. California Energy Commission Forecast (CEC 2002a) published in February 2002; Forecast for PG&E territory.
3. California Energy Commission Forecast, with 2006 gas price equal to the average gas price in 2001.

*actual 2001 average natural gas price in California (EIA 2002) with the missing November and December prices estimated using the proportional price changes of US natural gas wellhead prices.

California Natural Gas Price Forecast Scenarios



Appendix D. Allocation of Environmental Regulatory Risk in the DWR Contracts

	General New Regulations Implemented by:							**New Regulations Targeted to Energy Services Implemented By:**		
	Any Governmental Authority			Federal	State			Federal	State	
Seller	Parties can negotiate how to share costs above threshold, or Seller can terminate with no liability.	Seller passes on to DWR any cost increases above threshold	Seller shall not suffer the effects of any costs or restrictions imposed by environmental agencies.	Seller passes on to DWR any cost increases above threshold of $5.00 per MWh.	Any increase in cost for Seller passed on to DWR.	Any increase *or* decrease in cost for Seller passed on to DWR.	Parties will negotiate in good faith to leave Seller whole.	Seller can terminate with no termination payment	Any increase *or* decrease in cost for Seller (due to Legislature only) passed on to DWR.	DWR pays for increased cost or else defaults.
Non-Renewable Contracts										
Allegheny						✓				
Alliance Colton		Unclear**								
Calpeak								✓	Due to any agency of State	
Calpine – 1		$5 / MWh								
Calpine – 2		50¢ / MWh								
Calpine – 3		50¢ / MWh								
Calpine – 4									✓	
Coral Power								✓		✓
Dynegy – 1			✓							
Dynegy – 2			✓							
El Paso										
Fresno Cogeneration									✓	
GWF Energy	$2.5 M / yr								✓	
High Desert										
Morgan Stanley										
PacifiCorp									✓	
Sempra								✓		
Sunrise							✓			
Wellhead									✓	
Williams				✓	✓					
Renewable Contracts										
Capitol Power										
Clearwood										
County of Santa Cruz										
Imperial Valley										
PG&E Energy Trading										
Soledad						✓				
Whitewater										

Note: A number of these contracts have subsequently been renegotiated.
** The Alliance Colton contract claims that it is standard practice for contracts to allocate environmental risk in this manner, but it is unclear if the contract itself actually does.

Appendix E. DWR Non-Renewable Contract Summaries

See: http://eetd.lbl.gov/ea/EMS/EMS_pubs.html#RE

Appendix F. DWR Renewable Contract Summaries

See: http://eetd.lbl.gov/ea/EMS/EMS_pubs.html#RE